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ENERGY DEVELOPMENT: THE ENVIRONMENTAL TRADEOFFS

VOLUME 2: RELATIVE ENVIRONMENTAL ASSESSMENT OF METHODS TO INCREASE ENERGY PRODUCTION, CRUDE OIL, PIPELINE QUALITY GAS, AND ELECTRICITY FROM WESTERN COAL

STANFORD RESEARCH INSTITUTE

PREPARED FOR
ENVIRONMENTAL PROTECTION AGENCY

OCTOBER 1975

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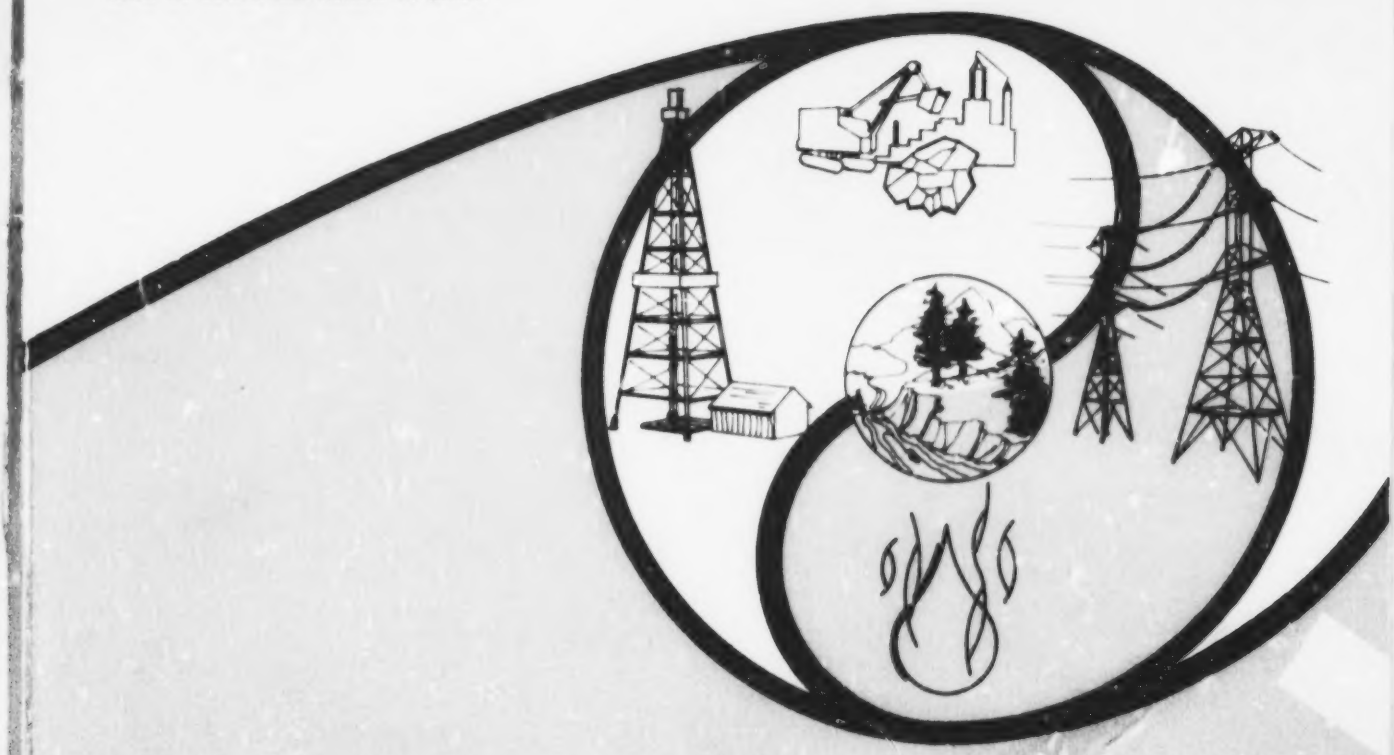
by . . .
Mark D. Levine and Robert V. Steele



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CONTENTS

LIST OF ILLUSTRATIONS v

LIST OF TABLES vi

PREFACE viii

ACKNOWLEDGMENTS ix

I INTRODUCTION 1

A. Objectives 1

B. Scope of Work 4

1. Scope of the Study "Energy Development: the Environmental Tradeoffs" 4
2. Scope of Volume Two, "Relative Environmental Assessment of Methods to Increase Energy Production 5

C. Methodology 6

1. Selection of Options for Increasing Energy Supply 7
2. Selection of Environmental Indicators 9
3. Determination of Impacts of Energy Supply Options. 9
4. Ranking of Energy Supply Options 9
5. Analysis of Critical Tradeoffs 10

References 12

II EVALUATION OF ENVIRONMENTAL IMPACTS FOR DEVELOPMENT AND USE OF WESTERN COAL FOR ELECTRICITY GENERATION 13

A. Introduction 13

1. Critical Environmental Issues 14
2. Energy Supply Potential 16

B. Summary and Conclusions 18

C. Analysis of Environmental and Social Impacts of Western Coal Options 18

1. SO_2 Impacts on Air Quality 19
2. NO_x Impacts on Air Quality and Oxidant Formation . 22
3. Particulate Toxic Trace Element Impacts on Air Quality 24

4. Population and Related Social Impacts 27
5. Land Use/Aesthetic Impacts 29
6. Water Consumption Relative to Availability 30
7. Water Quality 32
8. Cost of Electricity in the Midwest 33

D. Analysis of Impacts of Western Coal Options 34

1. Pro/Con Discussion 34
2. Analysis of Critical Tradeoffs 37

References and Notes 41

III EVALUATION OF ENVIRONMENTAL IMPACTS OF SELECTED OPTIONS FOR INCREASING U.S. OIL PRODUCTION 42

A. Introduction 42

1. Technology Overview 43
2. Energy Supply Potential of Options 48

B. Conclusions 51

C. Analysis of Environmental and Social Impacts of Options to Increase U.S. Oil Production 52

1. SO_2 Impacts on Air Quality 52
2. Particulate Impacts on Air Quality 56
3. NO_x Impacts on Air Quality 60
4. Population and Related Social Impacts 63
5. Water Consumption Relative to Availability 67
6. Land Use 70
7. Water Quality 72

D. Analysis of Critical Environmental Tradeoffs 74

1. Pro/Con Discussion 74
2. Analysis of Critical Tradeoffs 78

References and Notes 83

IV EVALUATION OF ENVIRONMENTAL IMPACTS OF FOUR OPTIONS FOR INCREASING PIPELINE QUALITY GAS SUPPLIES 86

A. Introduction 86

1. Technology and Impact Overview 87
2. Energy Supply Potential of Options 92

B. Conclusions 92

C. Analysis of Environmental and Social Impacts of the Options for Increasing Gas Production 94

1. Air Quality 94
2. Population 105
3. Land Use and Aesthetic Impacts 108
4. Water Consumption 111
5. Water Quality 113

D. Analysis of Critical Environmental Tradeoffs 115

1. Advantages and Disadvantages of Each Option . . . 115
2. Analysis of Critical Tradeoffs 116

References and Notes 119

ILLUSTRATIONS

II-1	Environmental Tradeoff Matrix for Options to Increase Electricity Production from Western Coal	37
III-1	Environmental Tradeoff Matrix for Options to Increase Domestic Oil Supplies	79
IV-1	Environmental Tradeoff Matrix for Options to Increase Pipeline Quality Gas Production	117

TABLES

II-1	Western Coal Reserves (Surface Only)	16
II-2	Possible Developments Schedules for Surface Mining of Western Coal	17
II-3	SO_2 Emissions for Western Coal Options	19
II-4	SO_2 Impacts on Air Quality Near a 1000 MW(e) Power Plant Using Western Coal	21
II-5	NO_x Emissions from Western Coal Options	22
II-6	NO_x Impacts on Air Quality Near a 1000 MW(e) Power Plant Using Western Coal	23
II-7	Particulate Emissions from Western Coal Options	24
II-8	Particulate Impacts on Air Quality Near a 1000 MW(e) Power Plant Using Western Coal	26
II-9	Population Increases in the West Due to Western Coal Development	28
II-10	Consumptive Use of Water for the Western Coal Development Options	30
III-1	Availability of Resources for Options to Increase Crude Oil Supply	49
III-2	Possible Development Schedules for Crude Oil Production	50
III-3	SO_2 Emissions from Oil Production Options	53
III-4	SO_2 Impacts on Air Quality Near a 100,000 Bbl/Day Crude Oil Production Facility	55
III-5	Particulate Emissions from Oil Production Options . . .	57
III-6	Particulate Impacts on Air Quality Near a 100,000 Bbl/Day Crude Oil Production Facility	58
III-7	NO_x Emissions From Oil Production Options	61
III-8	NO_x Impacts on Air Quality Near a 100,000 Bbl/Day Crude Oil Production Facility	62

III-9	Water Consumption to Produce Crude Oil	68
III-10	Probable Rankings of the Options to Increase Oil Supply Under Different Value Judgments	80
IV-1	Resource Availability for Options to Increase Pipeline Quality Gas Supply	93
IV-2	Possible Development Schedules for Pipeline Quality Gas Production	93
IV-3	Pollutant Emissions of the Pipeline Quality Gas Production Options	100
IV-4	SO_2 Impacts on Air Quality Near a 250 Million SCF/Day Pipeline Quality Gas Production Facility	101
IV-5	Particulate Impacts on Air Quality Near a 250 Million SCF/Day Pipeline Quality Gas Production Facility . . .	102
IV-6	NO_x Impacts on Air Quality Near a 250 Million SCF/Day Pipeline Quality Gas Production Facility . . .	103
IV-7	Population Increase Due to Construction and Operation of a 250 Million SCF/Day Coal Gasification Plant	106
IV-8	Water Consumption of 250 Million SCF/Day Coal Gasification Plants	111

PREFACE

This report, entitled "Relative Environmental Assessment of Methods to Increase Energy Production," constitutes the second volume of four in the series "Energy Development: the Environmental Tradeoffs." These reports have been prepared for the Office of Planning and Evaluation of the U.S. Environmental Protection Agency. Their purpose is to clarify issues related to critical environmental tradeoffs among options to increase domestic energy production. The reports have been designed to provide an initial assessment of factors that can influence policy-makers and interested citizens in their judgments of relative rankings of energy supply options with respect to environmental and social impacts. The four volumes of the report should be read with a full understanding that this assessment process is in its early stages and that much more work of this kind needs to be done before firm judgments can be supported by an adequate data base and careful analysis. We have issued these reports in the anticipation that they will contribute significantly to useful and enlightened debate on the relative environmental impacts of alternative methods of energy extraction and conversion.

This volume of the series provides an environmental tradeoff assessment for three sets of options to increase domestic energy supply. Set one consists of four options to produce electricity from western coal for use in the Midwest. Set two contains seven options for producing crude oil. Set three consists of four options to produce pipeline quality gas. Of the four volumes of the report, this one should be most useful to those interested in the development and application of a methodology for evaluating relative environmental impacts of alternative ways of producing energy.

ACKNOWLEDGMENTS

This volume of the series "Energy Development: the Environmental Tradeoffs" was authored by Drs. Mark D. Levine and Robert V. Steele. Dr. Levine was the project leader for the study and is directly responsible for Chapters I, II, and III of this volume. Dr. Steele authored Chapter IV of this volume and assisted in the research on the other chapters. Dr. Irving W. Yabroff contributed valuable advice to the authors, particularly regarding the organization of this volume of the report and the content of Chapter IV. Supervisory assistance was provided by Stephen L. Brown and Robert M. Rodden. Madeline J. Anderson typed and proofread the draft with great care and dedication. Phyllis Dorset edited the draft. Larry H. Oppenheimer contributed significantly to the development of ideas and concepts in this volume in his role as EPA project officer. The authors wish also to acknowledge the assistance of many of our colleagues in the Resources and Environment Programs of the Operations Evaluation Department of SRI.

Inquiries regarding the information presented in this or other volumes of the series "Energy Development: the Environmental Tradeoffs" should be directed to Robert M. Rodden (415) 326-6200, Ext. 3959, Mark D. Levine (415) 326-6200, Ext. 3157, or John Butler of EPA (202) 755-2733.

I. INTRODUCTION

A. Objectives

This report has been prepared for the Policy Planning Division of the Environmental Protection Agency to aid EPA in its formulation of policy regarding the development of new energy sources. This volume, the second of four in the series "Energy Development: the Environmental Tradeoffs" addresses the question of how adverse environmental impacts of energy development can be minimized by encouraging those projects and technologies that have lesser impacts than others. As such, the report has focused on the critical tradeoffs among different technologies or different sitings choices for the development of the same resource. The goal has been to elucidate the relative environmental tradeoffs among a well-defined set of choices.

In the past several years, EPA has initiated a number of studies whose purpose has been the gathering of data to quantify environmental impacts of energy production.[1-4] Other federal agencies have also supported the gathering and dissemination of environmental data relating to energy production, particularly for use in environmental impact statements. This is not to say that the data base for the evaluation of environmental impacts of energy-related activities is satisfactory or adequate in many areas; this study has uncovered many environmental problems for which the data are uncertain, incomplete, or nonexistent. Nonetheless, the establishment of a framework that can be used by citizens and decision-makers to discuss, evaluate, and ultimately resolve the desirability of developing one form of energy or another appears to us to be a critical need at this time.

No assessment of relative environmental consequences of alternative energy production strategies can be entirely free of value judgments. Indeed, EPA has explicitly requested that SRI provide its best judgment regarding the choices in this study. Value judgments, thoughtfully and reasonably based, are useful because there is no simple formula that will satisfy all or even most people concerning the relative significance of different adverse impacts on the environment. Persons most affected by a given energy development activity will undoubtedly see and feel more of the implications of that activity than of others. Californians may tend to be concerned about drilling for oil in the outer continental shelf. They will ask why the development of such alternative sources as oil shale are not encouraged more strongly. On the other hand, Coloradans opposed to oil shale development will argue that sources such as OCS oil should be favored. Persons and companies with a financial stake in one or another type of energy development will have yet a different point of view.

Final decisions on the form that domestic energy development will take has been, and will continue to be, a result of the complex interplay of varied interests which we call the political process. The role of federal, state, and local officials, energy developers, environmentalists, courts, and interested citizens will undoubtedly continue to be both important and poorly defined. It is the objective of this study to provide input into this process by suggesting a framework and supplying information to guide individuals who need to make decisions about environmental impacts of energy production. We have arrived at some judgments ourselves, and these are stated. We have also had to make a number of assumptions to carry out the analysis; these, too, have been stated to the best of our ability. It is proper that the assumptions be questioned; indeed, we see the dialogue consisting in part, at least, in the questioning of assumptions.

The intended audience of this report consists of the stakeholders mentioned in the preceding paragraph. The aim of directing the report at this audience has influenced the writing and, to a lesser extent, the research that went into the study. Although the analysis is technically based, we have endeavored to communicate the results in a nontechnical fashion. We might have chosen to include technical appendices; we did not for the goal has been to communicate to a wide audience throughout the report. Much of the organization of the report follows from this goal.

One of the assumptions of the study deserves special emphasis. We have based our analysis on what is known about and can reasonably be expected from current technology, for those technologies that are commercially available. For technologies still under development, we have made assumptions, which we deem to be reasonable, based on levels of application of control technology. It can be argued that at higher costs, more environmental cleanup is possible. In ten or fifteen years, technological improvements will make possible yet better measures for protecting the environment. Either of these factors, implementation of better and more costly control technology or future technological improvement, could serve to alter judgments about the relative environmental impacts of a given energy technology. It is our belief, however, that the analysis is better framed in terms of reasonable expectations regarding the implementation and efficacy of control technologies rather than in speculative terms about what might be accomplished. We thus agree, for example, that oil shale could be made "cleaner" than it is presently, at a cost, and that such improvements could change our judgment about its relative environmental impact. Furthermore, institutions could be developed that would minimize some of the social costs we have evaluated. We have not ignored these potential developments; in fact, we have strived to point out where they could be made to occur. Nonetheless, the analysis is firmly rooted in our sense of what will happen, given the current

capabilities of technology, the present environmental regulations of EPA and the states, and the anticipated costs of employing certain types of environmental control measures. As improvements in technology occur and as environmental regulations change, there will be a need for reconsideration of some of the judgments we have arrived at. Thus, it is important to observe that our judgments, or any judgments, about environmental effects of competing technologies need be constantly re-evaluated and updated as events unfold.

B. Scope of Work

1. Scope of the Study "Energy Development: the Environmental Tradeoffs"

As noted, the study consists of four separate volumes. Volume one is a brief summary of the major findings and conclusions. It also contains the most important of the information supporting these findings and conclusions. This volume, the second of four, contains the main body of the analysis of the relative environmental tradeoffs among three sets of options for increasing energy production: (1) four options for using western coal to produce electricity delivered to the Midwest, (2) seven options for producing crude oil, and (3) four options for producing pipeline quality gas. The objective of this volume is to provide a basis for forming informed judgments about the relative environmental costs of the options within each of the three sets. Volume three analyzes the relative environmental impacts of oil spills in 10 different offshore continental shelf regions. Volume four contains essential background information about the 15 technologies and the six environmental impact categories treated in the environmental tradeoff analysis. Volume four is designed to provide depth to the analysis of environmental tradeoffs contained in this volume of the report. As such, many of the references in this volume refer the reader to the relevant sections of volume four.

2. Scope of Volume Two, "Relative Environmental Assessment of Methods to Increase Energy Production"

Chapter II of this volume is concerned with the use of western coal to generate electricity. The issue is: how can western coal be converted into electricity in a manner so as to minimize adverse environmental impacts? The term "environmental impacts" is used here and elsewhere in the report in a broad sense to include social impacts as well. Four options are evaluated. These are:

1. Direct electricity generation on-site; transmission to the Midwest.
2. Low-Btu gasification on-site; combined cycle electricity generation; transmission to Midwest.
3. Coal transport to Midwest by rail; direct electricity generation in Midwest.
4. Coal transport to Midwest by rail; low-Btu gasification in Midwest; combined cycle electricity generation.

The results of the analysis of these options enable us to distinguish between the most and least environmentally adverse of the four options. Differentiation between the two options of intermediate impact requires the injection of value judgments to compare magnitudes of different impacts, social impacts versus air pollution impacts in populated regions. Additional analysis to quantify and possibly resolve the judgmental issues is suggested.

Chapter III analyzes the environmental issues with regard to increasing domestic crude oil supplies by seven different options. The critical tradeoffs among the options are derived to rank the most desirable and least desirable of the options. A more complete ranking of all the options is shown to require the application of value judgments. The seven options evaluated are:

1. Liquefaction of Midwestern Coal in the Midwest
2. Liquefaction of Western Coal in the West
3. Production of Synthetic Crude Oil from Oil Shale

4. Oil from the Outer Continental Shelf (Mid-Atlantic OCS)

5. Oil from Onshore Alaska

6. Assisted Recovery of Oil--Micellar Flood and CO_2 Miscible Methods

7. Assisted Recovery of Oil--Steam Injection Methods.

The environmental analysis of four different options for increasing pipeline quality gas supplies, reported in Chapter IV, is carried out in a manner similar to that for the oil options. Due to the smaller number of options considered, a more definitive ranking is achieved. The four options considered in this section are:

1. Mine western coal, gasify it on-site and pipe it to the Midwest

2. Mine midwestern (Illinois) coal and gasify it near the site

3. Produce gas from wells at offshore locations (Atlantic and Southern California OCS) and pipe it ashore

4. Produce gas from wells in Alaska, liquefy it and ship it to the West Coast via liquefied natural gas tankers.

C. Methodology

The essential analytical problem of this study is that of providing a partial basis for judgments about the relative merits of different methods of energy production based on environmental considerations. Three considerations were especially important in the formulation of the methodology: (1) the need to exclude value judgments from a portion of the analysis to establish an essentially "value-free" data base, (2) the need to make explicit the value judgments that entered the analysis, and (3) the practical need to evolve an approach to permit comparison of critical tradeoffs of energy production options so that conclusions could be reached. What follows is a summary of the key steps that have been developed to fulfill these criteria.

1. Selection of Options for Increasing Energy Supply

a. Limitation of the Analysis of Fossil Fuels

The selection of measures to increase energy supply was limited to the production of fossil fuels. The fossil fuel options were chosen to illustrate the range of expected environmental problems based on EPA's judgments about (1) new energy augmentation measures most likely to contribute to domestic energy supply within the next two decades and (2) measures for which relative environmental tradeoffs are not adequately understood. No attempt was made to include nonfossil fuel alternatives such as nuclear power. The nonfossil fuel options were excluded to simplify formulation of the methodology. We suggest that one logical extension of the methodology lies in extending the analysis to nuclear power and other energy technologies.

b. Comparison of Options which Produce Energy of the Same Form

An important aspect of the methodology is the fact that environmental comparisons are made only among options which produce the same end product. It is beyond the scope of the analysis to compare the environmental impacts of generating electricity with those of producing oil, for example. This does not mean that such comparisons among different energy forms would not be interesting or useful. For example, an analysis of whether western coal is better used in the production of high Btu gas, crude oil, or electricity would be of great interest. For a number of reasons, such comparisons are not made in this research. First, tradeoffs other than environmental ones will play a major role in any analysis of these issues. The perceived need of the nation for oil to provide protection from uncertain foreign sources is relevant to the analysis of alternative uses of western coal, as are a host of other similar considerations, such as regional patterns of energy demands for different forms of energy.

A second factor in the decision to limit the analysis to options that produce the same form of energy is the complexity of comparing environmental impacts of different energy forms. To illustrate, we note the example of two uses of coal: for electricity and oil production. Oil has a variety of different end uses, ranging from firing boilers to fueling automobiles. The efficiencies of these end uses vary greatly, as do the environmental impacts. Electricity also has a variety of end uses, although the efficiencies and environmental impacts of these end uses do not vary as greatly as do those for oil. For electricity, a substantial portion of the environmental impacts as well as the energy losses occurs in the front end of the production cycle--i.e., in the production of the electricity itself. For oil, a large proportion of the environmental impact and energy losses occur at the point of end use. Thus, to make a meaningful comparison between the two forms of energy, it is necessary to evaluate impacts to the point of end use for a multiplicity of end uses. The utility of performing such an analysis is in some instances questionable. For example, the decision of whether or not the incremental unit of energy should be gasoline for automobiles or electricity for appliances depends largely on whether society judges (through the marketplace) the additional automobile or appliance to be more socially useful. An environmental assessment of the impacts of the automobile versus the electric appliance thus represents an evaluation of the costs of activities whose benefits are wholly disproportionate and which cannot be easily equated.

The problem of comparing diverse social benefits is avoided by restricting the comparisons to those between different options which produce energy of the same form. For these comparisons, the end uses can be considered identical and thus factored out of the analysis. We suggest that some of the conceptual problems of prior work that has made comparisons among fuel types have resulted from a lack of appreciation of the nature of the problem arising from interfuel comparisons.

2. Selection of Environmental Indicators

Two objectives dominated our selection of environmental indicators: (1) the need to encompass the totality of environmental effects of diverse technologies and development activities and (2) the desire to limit the number of indicators to facilitate communication of the results and to keep the analysis within manageable bounds. To balance these two objectives, we have defined a small set of environmental indicators to reflect physical alterations of the environment, human health effects, resource depletion (specifically, water depletion), and social impacts. The indicators that we have chosen are:

a. SO_2 Impacts on Air Quality

b. NO_x Impacts on Air Quality

c. Particulate Impacts on Air Quality

d. Population

e. Aesthetics/Land Use

f. Water Consumption Relative to Availability

g. Water Quality

3. Determination of Impacts of Energy Supply Options

For each of the impact categories, quantitative estimates of the impacts were made wherever possible. We assumed the application of state-of-the-art control technology, or of control technology adequate to meet current environmental regulations. We also surveyed industry plans, engineering designs, and independent evaluations to determine the applicability of the assumptions regarding the efficiency of control technologies and the likelihood of their implementation.

4. Ranking of Energy Supply Options

For each of the options to be compared with one another, relative rankings were established with regard to the seven environ-

mental indicators. The rankings, which ranged from "least adverse" to "intermediate" to "most adverse," were determined on the basis of both the quantitative impacts and relevant qualitative considerations. The inclusion of qualitative factors is an essential ingredient of the ranking methodology. For example, equal quantities of emissions to the air of a technology located in two different areas can have vastly different human health impacts, depending on background levels of air pollution in the areas, the density and composition of nearby populations, topography, etc. This example illustrates the need for a broad assessment of factors that are difficult to quantify (and whose quantification is beyond the scope of the study) to arrive at appropriate rankings. For cases in which inadequate information or ambiguity about possible variations in the implementation of the energy supply option existed, we indicated a variable ranking (for example, from "intermediate" to "least adverse"). In all instances, the ranking was based on an assessment of the impacts of an option relative to the other options. No attempt was made to establish a ranking based on an absolute level of impact.

5. Analysis of Critical Tradeoffs

Once all of the options within a given set were ranked for each of the environmental indicators, there was the difficult problem of assessing all of this information to arrive at relative judgments about the overall impacts of the options. The first step was to summarize the relative advantages and disadvantages of the options in a pro/con type of discussion. This made possible the delineation of the critical environmental tradeoffs differentiating the options. The analysis, if only carried to the point of focusing attention on the critical tradeoffs, was valuable in defining the key issues that should be addressed by environmental research and analysis. We extended the analysis by seeking to indicate dominance among the options with regard to the number and severity of "most adverse" and "least adverse" rankings.

It is our judgment that additional avenues of inquiry might fruitfully extend the analysis to further focus attention on the critical environmental decision elements of alternative measures to increase energy supply. One such extension of the methodology is indicated in Chapter II, Section D2, "Analysis of Critical Tradeoffs," in which additional analysis is suggested to investigate the feasibility and cost of reducing critical environmental impacts of the options by study of alternative siting choices available for energy conversion facilities. In general, future study could contribute to environmentally sensitive energy policy formulation by (1) investigating the costs of reducing adverse environmental impacts of the energy supply options and (2) studying in depth, quantitatively when possible, the effects of the residual environmental impacts. Until the economic evaluation of environmental control and the environmental tradeoff assessments are made somewhat more quantitative, the final rankings of many of the options will have to be considered tentative.

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1. "Environmental Impacts, Efficiency and Costs of nergy Supply and End Use," Hittman Associates, Inc., Report No. HIT-561 (January 1975).

2. "Environmental Considerations in Future Energy Growth," Battelle Memorial Laboratory, EPA Contract No. 68-01-0470 (April 1973).

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4. "Control of Environmental Impacts from Advanced Energy Sources," Stanford Research Institute, Report No. EPA-600/2-74-002 (March 1974).

II. EVALUATION OF ENVIRONMENTAL IMPACTS FOR DEVELOPMENT AND USE OF WESTERN COAL FOR ELECTRICITY GENERATION

A. Introduction

Critical and difficult decisions about increasing U.S. energy production are being considered at the present time. One such decision relates to the development of western coal reserves. Even before the recent energy shortages, plans for mining the massive low-sulfur coal deposits of the American West were formulated and discussed within industry and government. As a result of these plans, western coal production is expected to increase by almost an order of magnitude between the present and the mid-1980s. Many observers expect that the West will supply over half of the annual U.S. coal needs before two decades have elapsed.[1]

This chapter does not attempt to determine an optimum or satisfactory rate of western coal development although this question is ultimately of crucial significance. Rather, it treats the question of how the environmental and social impacts of western coal development can be minimized, once an appropriate level of coal production has been determined. The analysis considers four options for producing electricity from western coal after it has been minded. The four options have been chosen to investigate two ways of reducing adverse environmental impacts: (1) by the selection of technology for conversion and (2) by the selection of an area or region for the siting of coal conversion. Since the Midwest is likely to provide the largest market for western energy resources, all of the options assume that the final product, electricity, is delivered to that area. The four options are:

1. Direct electricity generation on-site; transmission to the Midwest.
2. Low-Btu gasification on-site; combined cycle electricity generation; transmission to Midwest.

3. Coal transport to Midwest by rail; direct electricity generation in Midwest.

4. Coal transport to Midwest by rail; low-Btu gasification in Midwest; combined cycle electricity generation.

The analysis provides information pertinent to an evaluation and ranking of these four options for increasing western energy production in terms of their social and environmental impacts. Eight indicators of impacts have been selected to illustrate the types of problems associated with delivering electricity derived from western coal to the Midwest. These are impacts associated with:

1. SO_2 impacts on air quality
2. NO_x impacts on air quality
3. Particulate and toxic trace element impacts on air quality
4. Population and related social impacts
5. Land use/aesthetics
6. Water consumption relative to availability
7. Potential for degrading water quality
8. Cost of electricity.

The cost of electricity, while not strictly an environmental or social impact, is included as an indicator of the options that are most likely to occur in the absence of consideration of social and environmental costs.

1. Critical Environmental Issues

The following discussion provides a brief overview of the particular relevance of environmental impacts to the coal regions in the western United States.

Air pollution is of concern, primarily because the air in the West is presently undegraded compared with that in other parts of the country. Energy development could severely impact air quality, causing aesthetic problems in rural and wilderness areas and possible health problems if the energy development area is or becomes urbanized. Portions of the West could be subject to conditions of stagnant air, which exacerbate the effects of pollutants in the atmosphere.[2]

Population and related social impacts have already, in early stages of western energy development, been very troublesome in localities that have undergone rapid population growth. Because small communities subject to intense growth due to nearby energy development rarely have the resources to plan and structure growth, adverse social impacts are not easily controlled.[3]

Land use and aesthetic problems constitute another issue in a region of the country with large expanses of relatively undisturbed land. Uncertainties about long-term success of rehabilitation of mined areas in the arid West, the alienation of land rights-of-way for power lines, pipelines, and rail lines, and the siting of energy conversion facilities constitute components of the aesthetic impact of energy development.

Water consumption in the West is a major issue in coal resource development because of the scarcity of water. The rapid rate of proposed development requires fundamental decisions to be made on the allocation of these scarce water resources in the next few years. The task of providing sufficient water for energy development while maintaining the ecology of the streams during periods of drought and assuring ranchers of adequate supplies of water is extremely complex and requires both extensive information and a determination by the people of the West of their priorities for the future. The fact that Montana has established a 3-year moratorium on allocation of water rights and that the governor of North Dakota has decided to do the same suggests that the information

base is not yet adequate and priorities have not yet been agreed on by the people.[4]

Degradation of water quality is also a significant concern, because of the scarcity of water for irrigation and other uses. For example, if the salinity of surface water is further increased in some rivers (e.g., portions of the Colorado River), the water may be so degraded that it is unfit for many productive uses.

2. Energy Supply Potential

The large surface deposits of coal in the western United States, in combination with low cost of recovery, provide an attractive source for future expansion of coal development. Table II-1 shows the most recent Bureau of Mines estimates of coal reserves suitable for surface mining in the coal-bearing states of the West. Montana and Wyoming possess the largest subbituminuous surface coal reserves in the West, more than 30 times current annual national coal consumption. North Dakota possesses large quantities of lignite, which is not considered suitable for use in power plants but may be used for coal gasification.

Table II-1

WESTERN COAL RESERVES (SURFACE ONLY)[5]

States	Reserves (Billions of tons)
Arizona	0.35
Colorado	0.87
Montana	43
New Mexico	2.3
North Dakota	16
South Dakota	0.43
Utah	0.26
Washington	0.51
Wyoming	24

Although there are also large underground reserves in the West, they have not been included in Table II-1. This is because many of the underground deposits have very thick seams which require advanced technology for efficient recovery. Such technology for mining underground coal deposits is not available today, nor is it likely to be developed while large, easily recoverable surface reserves are available. Other deep deposits that are more amenable to current extraction technology will probably be developed, and indeed, many are currently being developed.

Potential development schedules for western surface coal reserves, as estimated in the Project Independence report, are shown in Table II-2. The "low" and "high" development schedules correspond to the Project Independence "business as usual" and "accelerated development" case, respectively. These numbers should be compared with the current national coal consumption of 550 million tons per year.

Table II-2

POSSIBLE DEVELOPMENT SCHEDULES FOR SURFACE MINING OF WESTERN COAL[6]

	Western Coal Development Schedules in Million Tons Per Year	
Year	Low	High
1980	130	240
1990	240	490

Not all of the coal recovered will be used to produce electric power, although in the near term a large fraction of it almost certainly will. In the longer term, as synthetic fuels place demands on coal production, a smaller fraction of the extracted coal is likely to be devoted to electric power production. If all the coal were to be used for electric power production, then from 37 to 69 1000 MW(e) power plants could be supported in 1980, and from 69 to 140 1000 MW(e) plants could be supported in 1990, according to the schedules in Table II-2.

B. Summary and Conclusions

The data and analysis presented in this chapter have led us to conclude that:

- Low-Btu gasification/combined-cycle electricity generation is a less environmentally damaging method of producing electricity than steam electricity generation using the best available control technologies.
- The critical tradeoffs between steam electricity generation in the West and in the Midwest (options 2 and 3, respectively) are the adverse social impacts, high water consumption relative to water availability, and potential for degrading presently clear air in the West versus the high levels of air pollution near populated areas in the Midwest; siting of power plants in less densely populated areas of the Midwest may reduce the adverse air pollution impacts of option 3.
- Low-Btu gasification/combined-cycle electricity generation in the Midwest (option 4) has significantly lower social and water consumption impacts than the same technology sited in the West (option 2); other environmental impacts of the technology are comparable for the two siting choices.

Thus, we recommend that emphasis be placed on appropriate research and development efforts to make combined-cycle electricity generation more efficient and competitive with steam electricity generation. A successful R&D program combined with the siting of these plants in the Midwest (near the user) will substantially reduce adverse environmental impacts of electricity production. If current methods of steam electricity generation are used, the preferred siting location appears to be in the Midwest rather than the West, if sites removed from densely populated areas can be found.

C. Analysis of Environmental and Social Impacts of Western Coal Options

The discussion of impacts focuses on factors that are significant in ranking the four options of developing and using western coal. In general, if the difference in impacts among the options appears not

greater than approximately 25 percent, we have ranked them equal. For example, although all of the options are likely to cause degradation of the water quality in the West (through disruption of aquifers), the impact is comparable for all options and is not discussed.* We have also not differentiated impacts among the options if the information base to do so was judged inadequate. For the cost of electricity impact, a difference of 10 percent is considered significant, if the cost data are reliable.

1. SO_2 Impacts on Air Quality[2]

SO_2 emission from the four options are shown in Table II-3.

Table II-3

SO_2 EMISSIONS FOR WESTERN COAL OPTIONS

	SO_2 Emissions (tons/10^{12} Btu electrical output)
Option 1	500-2000
Option 2	45-65
Option 3	450-1800
Option 4	40-60

*Because present technology for low-Btu gasification/combined cycle electricity generation (options 2 and 4) is 20 percent less efficient than direct burning of western coal in the production of electricity, disruption of aquifers and other mechanisms for water quality degradation associated with mining is approximately 20 percent greater for the gasification options. As noted above, such differences are not sufficiently great to show up in the analysis.

For all options, western coal with an average sulfur content of 0.8 percent is assumed. For the options that burn coal directly to generate electricity (1 and 3), estimated SO_2 emissions are based on the assumption that the power plant is fitted with stack gas scrubbers that have an efficiency of 40 percent to 85 percent in the removal of SO_2.* For the low-Btu gasification options (2 and 4), SO_2 emissions occur during both the gasification and electricity generation stages of the process. The lower estimate is for an advanced fluidized-bed gasification process; the higher, for the Koppers-Totzek process. Lurgi gasification falls in the middle of the range.

Impacts on air quality of SO_2 emissions from power plants in the West and Midwest are shown in Table II-4. Direct burning of coal in either the West or Midwest can cause the strictest (Class I) air quality standards to be exceeded during a 3-hour or 24-hour period under worst case conditions.[2] The impact on short-term air quality is significantly less for the low-Btu gasification/combined cycle options. Although the difference in long-term air quality is not as striking, reductions in annual average concentrations of SO_2 may be achieved by up to a factor of 10 in options 2 and 4 compared to options 1 and 3.

The relative rankings for SO_2 impacts are shown below. Options 2 and 4 are rated "least adverse," because SO_2 emissions and impacts on air quality are low. The distinction between the rankings for options 1 and 3, both of which produce equally high SO_2 impacts on air quality, is that the emissions of option 1 are less likely to cause adverse health impacts, since they occur in areas not heavily populated, while option 3 pollutes the populated Midwest. Option 1 is given a variable ranking, ranging from "intermediate" to "most adverse," depending on the siting choice in the

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*The proposed power plants at Colstrip, Montana, have been designed to use scrubbers of 40 percent efficiency of SO_2 removal. A removal efficiency of 85 percent has been chosen as an estimate of the capability of near-term technology.

Table II-4

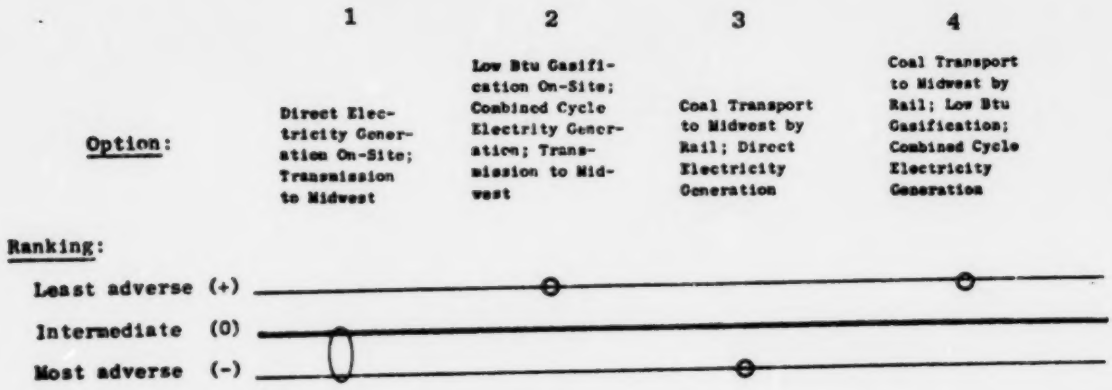
SO_2 IMPACTS ON AIR QUALITY NEAR A 1000 MW(e) POWER PLANT USING WESTERN COAL

SO_2 Concentration/Ambient Air Quality Standard

Option	3 hr (Worst Case)			24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I	Class III	Class II	Class I
1. Direct burning in west	0.06-0.24	0.11-0.45	3.1-13	0.04-0.18	0.11-0.47	2.2-9.4	0.01-0.04	0.04-0.17	0.30-1.3
2. Combined cycle in west	0.01-0.02	0.02-0.03	0.64-0.88	0.01-0.02	0.03-0.04	0.62-0.86	0.08-0.01	0.03-0.04	0.23-0.32
3. Direct burning in midwest	0.06-0.24	0.11-0.45	3.1-13	0.04-0.18	0.11-0.47	2.2-9.4	0.01-0.03	0.03-0.11	0.20-0.85
4. Combined cycle in midwest	0.01-0.02	0.02-0.03	0.64-0.88	0.01-0.02	0.03-0.04	0.62-0.86	0.003-0.004	0.01-0.02	0.10-0.12

West (proximity to people and likelihood of degrading presently undegraded air). Option 3 receives a "most adverse" ranking.

Rankings for SO_2 Impacts


1
2
3
4
Option:
Direct Electricity Generation On-Site; Transmission to Midwest
Low Btu Gasification On-Site; Combined Cycle Electrity Generation; Transmission to Midwest
Coal Transport to Midwest by Rail; Direct Electricity Generation
Coal Transport to Midwest by Rail; Low Btu Gasification; Combined Cycle Electricity Generation
Ranking:
Least adverse (+)
Intermediate (0)
Most adverse (-)

2. NO_x Impacts on Air Quality and Oxidant Formation

The emissions of nitrogen oxides from each option are shown in Table II-5, while the resulting impacts on air quality are shown in Table II-6.

Table II-5

NO_x EMISSIONS FROM WESTERN COAL OPTIONS

	NO_x Emissions (tons per 10^{12} Btu electrical output)
Option 1	1000-1400
Option 2	30-55
Option 3	1050-1450*
Option 4	100-120*

*Includes NO_x emissions of 70 tons per 10^{12} Btu due to transport of coal.

Table II-6

NO_x IMPACTS ON AIR QUALITY NEAR A 1000 MW(e) POWER PLANT USING WESTERN COAL

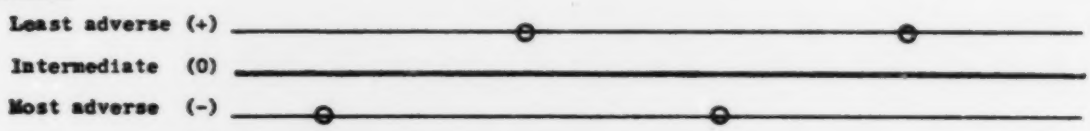
Option	Annual Average
1. Direct burning in West	0.02
2. Combined cycle in West	0.001
3. Direct burning in Midwest	0.01
4. Combined cycle in Midwest	0.0004

Low-Btu gasification followed by combined cycle power generation is an extremely effective method of controlling NO_x emissions because of the low level of emission from gas turbine combustion. Direct combustion of coal, on the other hand, produces considerably higher levels of NO_x. In general, NO_x emissions from one 1000 MW(e) power plant will not by themselves cause the air quality to exceed the standard. However, photochemically induced reactions of NO_x with hydrocarbons and/or other air pollutants could lead to a significant concentration of oxidants. The potential for oxidant formation is highly site-specific; it tends to be high in areas with stagnant wind conditions, large amounts of sunlight, and high background levels of air pollutants (especially reactive hydrocarbons and NO_x). High altitudes may also increase the rate of formation of photochemical smog. On the basis of present evidence, we are not able to determine whether conditions in the West or in the Midwest are more likely to produce photochemical smog from the high NO_x emissions due to direct electricity generation from coal.

Rankings for NO_x Impacts

Option:	1	2	3	4
	Direct Electricity Generation On-Site; Transmission to Midwest	Low Btu Gasification On-Site; Combined Cycle Electrity Generation; Transmission to Midwest	Coal Transport to Midwest by Rail; Direct Electricity Generation	Coal Transport to Midwest by Rail; Low Btu Gasification; Combined Cycle Electricity Generation

Ranking:



3. Particulate Toxic Trace Element Impacts on Air Quality

The particulate emissions of each option are shown in Table II-7.

Table II-7

PARTICULATE EMISSIONS FROM WESTERN COAL OPTIONS

	Particulate Emissions (tons per 10^{12} Btu electrical output)	
	On-Site	During Loading and Transport
Option 1	70	0
Option 2	2-44	0
Option 3	60	1500
Option 4	2-40	1900

The coal exporting options 3 and 4 produce many times the emissions of particles as the on-site electricity generation options, due to particulate emissions during loading and transport of coal. The impact of the emissions during loading and transport is considerably less than that from burning because loading and transport release primarily large

particles (greater than 3 microns in diameter), which are rapidly deposited near the emission source. These particulate emissions are responsible for some property damage near the coal loading and unloading sites and near the rail corridor.

Particulate emissions from direct burning of coal (options 1 and 3) are reduced to levels below the federal new source performance standards through the use of electrostatic precipitators with a 99.5 percent efficiency. Gas scrubbing processes reduce particulate emissions from the low-Btu gasification process to less than one-third of comparison federal performance standards.

Emission of fine particles at the site of electricity generation is a problem judged more serious than that posed by the emission of coarse particles, discussed above. Electrostatic precipitators and gas scrubbers are not presently capable of removing most particles below 0.2 micron in diameter. The small particles remain airborne for long periods of time and they also constitute the component of particulate emissions responsible for adverse health effects. By far the largest number of particles emitted from stacks after electrostatic precipitation are fine particles.

Toxic trace elements contained in the coal can be emitted to the air along with particles; in fact, toxic trace elements tend to adhere to the surface of fine particles, due to the large surface area of a mass of fine particles. On the basis of a simple model calculation (described in Chapter VI of Volume IV), however, we conclude that for the four options, toxic trace element emissions will probably not cause significant air pollution hazards with the possible exception of fluorine, selenium, and mercury.

The impacts on air quality from particulate emissions are shown in Table II-8. Ambient air concentrations of particulate matter are always less for options 2 and 4 than for options 1 and 3, although standards

Table II-8

PARTICULATE IMPACTS ON AIR QUALITY NEAR A 1000 MW(e) POWER PLANT USING WESTERN COAL

Particulate Concentration/Ambient Air Quality Standard

Option	24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I
1. Direct burning in west	0.01	0.06	0.17	0.002	0.009	0.02
2. Combined cycle in west	0-0.01	0-0.04	0.001-0.12	0-0.001	0-0.006	0-0.01
3. Direct burning in midwest	0.01	0.06	0.17	0.001	0.006	0.01
4. Combined cycle in midwest	0-0.01	0-0.04	0.001-0.12	0-0.001	0-0.004	0.-0.01

will not be exceeded under any conditions.* As shown below, we judge the impacts of the fine particulate emissions to be more adverse in the Midwest than the West. The reason for this judgment is that fine particles travel long distances in the air before settling; thus, any emissions in the Midwest, regardless of siting choice, can result in an increased level of particulates coming into contact with and causing adverse health impacts on large numbers of people.

Rankings for Particulate Impacts

Option:	1 Direct Electricity Generation On-Site; Transmission to Midwest	2 Low Btu Gasification On-Site; Combined Cycle Electrity Generation; Transmission to Midwest	3 Coal Transport to Midwest by Rail; Direct Electricity Generation	4 Coal Transport to Midwest by Rail; Low Btu Gasification; Combined Cycle Electricity Generation
Ranking:				
Least adverse (+)		●		
Intermediate (0)	●			●
Most adverse (-)			●	

4. Population and Related Social Impacts

Current projections of western coal development suggest that the production of western coal will expand by a factor of 10 or more between the present and 1985. For example, the "most likely case" projection of the Northern Great Plains Resources Program Study, encompassing northern Wyoming, eastern Montana, and parts of North Dakota anticipates an increase from 16 million tons to 190 million tons annually between

* Because the air quality standards do not differentiate between fine and coarse particles, concentrations of fine particles below the standard may cause significant adverse health impacts.

1970 and 1985.[1*] Because of the rapid rate of development and the limited time available for the planning and growth of new institutions in the West, the social impacts on the towns and rural areas are likely to be severe. A measure of the severity of the impact is the number of people who will move into the area as a result of each of the options. An approximate estimate of population increases, useful for comparing the options, is presented in Table II-9. These increases are added to a base level of approximately 400,000 people presently residing in the coal-bearing regions in Montana, Wyoming, and North Dakota with moderate growth projected into the 1980s. Options 3 and 4 will tend to increase the population of the Midwest in a way comparable to the population increase in the West due

Table II-9

POPULATION INCREASES IN THE WEST DUE TO WESTERN COAL DEVELOPMENT

	Estimated Permanent Population Increase in the West per 10^{15} Btu/Year Electrical Output*	Estimated Temporary Population Increase in the West per 10^{15} Btu/Year Electrical Output†
Option 1	55,000-85,000	30,000-50,000
Option 2	100,000-180,000	30,000-50,000
Option 3	<30,000	small
Option 4	<30,000	small

* Includes permanent employees, their families, and persons induced to move into the area because of coal mining and related industrial activity. Chapter III of Volume IV explains how the numbers were estimated.

† Includes construction workers, their families, and induced population. The numbers quoted are for an "average" year. Peak construction years could have a significantly larger construction population, but the associated population would probably not increase commensurately. We have assumed the same labor force to build a low-Btu gasification/combined cycle plant as for a direct electrical generating facility.

* 190 million tons of coal will yield an amount of electricity equivalent to approximately 10^{15} Btu using any of the four western coal options.

to options 1 and 2. In the Midwest, however, the present population is much larger and can absorb the additional people without serious social and institutional impacts. Based on these considerations, the rankings of the options are shown below.

Rankings for Population Impacts

Option:	1 Direct Electricity Generation On-Site; Transmission to Midwest	2 Low Btu Gasification On-Site; Combined Cycle Electrity Generation; Transmission to Midwest	3 Coal Transport to Midwest by Rail; Direct Electricity Generation	4 Coal Transport to Midwest by Rail; Low Btu Gasification; Combined Cycle Electricity Generation
Ranking:				
Least adverse (+)			O	O
Intermediate (0)				
Most adverse (-)	O	O		

5. Land Use/Aesthetic Impacts

Three factors are considered in determining impacts due to land disturbance associated with the four western coal options:

(a) Land disturbed by mining is 20 percent greater for the gasification options (2 and 4). This difference amounts to 0.2 square miles per 10^{15} Btu of electricity produced.[7]

(b) Transmission lines spanning 1200 miles are required for on-site electricity generation options (1 and 2). The right-of-way for this transmission line amounts to 20 square miles. Assuming that one transmission line is needed per 1000 MW(e) facility and that the lifetime of the power plant is approximately 20 years, options 1 and 2 require that 50 square miles per 10^{15} Btu of electricity be used for power lines.

(c) New spur lines need be built to transport coal to the Midwest by rail.

Because the rail lines are short, the land impact is minimal. The predominant effect is that associated with transmission lines. For this reason, options 1 and 2 are judged to have the most adverse land impact.

Rankings for Land Use/Aesthetic Impacts

Option:	1 Direct Electricity Generation On-Site; Transmission to Midwest	2 Low Btu Gasification On-Site; Combined Cycle Electrity Generation; Transmission to Midwest	3 Coal Transport to Midwest by Rail; Direct Electricity Generation	4 Coal Transport to Midwest by Rail; Low Btu Gasification; Combined Cycle Electricity Generation
Ranking:				
Least adverse (+)			○	○
Intermediate (0)				
Most adverse (-)	○	○		

6. Water Consumption Relative to Availability[4]

The estimated western water requirements for each of the four options are shown in Table II-10. The water consumption in option 1 is

Table II-10

CONSUMPTIVE USE OF WATER FOR THE WESTERN COAL DEVELOPMENT OPTIONS

	Water Consumption in the West (thousands of acre-feet per 10^{15} Btu electrical output)
Option 1	750-950[a]
Option 2	600-1500[b]
Option 3	~2*
Option 4	~2*

[a] Reference 8

[b] Reference 9

* Water required for mining and revegetation in the West.

that associated with the use of wet cooling towers. If dry cooling towers are used (at an increased cost of electricity of approximately 20 percent), the water requirements are reduced to about 160,000 acre-feet per 10^{15} Btu electrical output.[10] For option 2, the lower estimate of water consumption is for the use of dry cooling towers; the higher estimate, for wet cooling towers.

The availability of water in the coal-bearing regions of the West can be described as follows: rivers and tributaries in the Yellowstone Basin, which provide most of the water in the coal lands of Montana, north and east Wyoming, and North Dakota,* could yield almost 2,000,000 acre-feet to energy producing industries in an average year. Two important problems would result from such allocation of water: (1) during drought years, which occur every one or two decades, instream flows could drop so low as to threaten aquatic life in the streams and rivers of the region and (2) expansion of the present irrigation withdrawals for agricultural purposes of 2.4 million acre-feet per year would be impossible, eliminating any increase in irrigable lands. An extensive system of aqueducts could provide an additional 2 million acre-feet per year to the Northern Great Plains coal lands; such a system of aqueducts would in themselves cause significant social and environmental impacts.

The rivers in the Colorado Basin provide the only source of surface water for development in eastern Wyoming, Colorado, and large portions of Utah, New Mexico, and Arizona. The analysis of water availability in the Colorado Basin, presented in Chapter IV of Volume IV, indicate the scarcity of water in the Colorado Basin compared with that of the Missouri Basin. Substantial diversions of water from the Colorado Basin to energy

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*The rivers referred to are the Big Horn, Tongue, Powder, and Yellowstone, all of which are combined into the Yellowstone west of the North Dakota border.

development will significantly reduce the future water availability in the regions for agricultural and other non-energy uses.

On the basis of the scarcity of water in the West and the general availability of water in the Midwest, the relative rankings for the four options are as shown below.

Rankings for Water Consumption
Relative to Availability Impacts

Option:	1 Direct Electricity Generation On-Site; Transmission to Midwest	2 Low Btu Gasification On-Site; Combined Cycle Electrity Generation; Transmission to Midwest	3 Coal Transport to Midwest by Rail; Direct Electricity Generation	4 Coal Transport to Midwest by Rail; Low Btu Gasification; Combined Cycle Electricity Generation
Ranking:				
Least adverse (+)			⊖	⊖
Intermediate (0)				
Most adverse (-)	⊖	⊖		

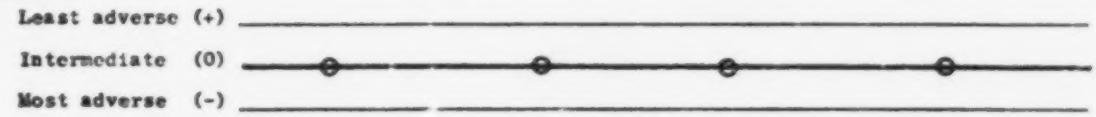
7. Water Quality

Water quality impacts of the four options are primarily associated with the mining of coal. Because the four options differ by only 20 percent in land disturbance due to mining, no differential impacts among the options are noted.

Ranking for Water Quality Impacts

Option:	1 Direct Electricity Generation On-Site; Transmission to Midwest	2 Low Btu Gasification On-Site; Combined Cycle Electrity Generation; Transmission to Midwest	3 Coal Transport to Midwest by Rail; Direct Electricity Generation	4 Coal Transport to Midwest by Rail; Low Btu Gasification; Combined Cycle Electricity Generation

Ranking:



8. Cost of Electricity in the Midwest

This comparison is for the cost of electricity delivered to the Midwest. Electricity costs for option 1 (on-site burning and transmission of electricity) and option 3 (transporting coal and burning in Midwest) are approximately equal: \$3.7 million per 10^{12} Btu.* The cost of electricity from low-Btu coal gasification plants using current technology indicate that it is not yet competitive with direct burning of coal to generate electricity. The most likely prospects are that low-Btu gasification will be competitive with direct burning of coal in the mid-1980s, after technological improvements are made in the combined cycle process to improve the efficiency of the operation.

*Based on a unit train shipping rate of 5 mils per ton-mile for coal (at 17.2×10^6 Btu per ton) and a rate of 3.5 mils per kW-hr for electrical transmission via 500 kV line.

Rankings for Cost of Electricity Impacts

Option:	1 Direct Electricity Generation On-Site; Transmission to Midwest	2 Low Btu Gasification On-Site; Combined Cycle Electrity Generation; Transmission to Midwest	3 Coal Transport to Midwest by Rail; Direct Electricity Generation	4 Coal Transport to Midwest by Rail; Low Btu Gasification; Combined Cycle Electricit; Generation
Ranking:				
Least adverse (+)	⊖		⊖	
Intermediate (0)				
Most adverse (-)		⊖		⊖

D. Analysis of Impacts of Western Coal Options

1. Pro/Con Discussion

The discussion of advantages and disadvantages of the western coal options is meant to summarize and clarify the information and judgments contained in Section C. The pros and cons of the impacts, as they relate to the western coal options, are given below.

Option 1: Direct electricity generation on-site; transmission to Midwest

Advantages

- Cost of electricity is less than for low-Btu gasification (options 2 and 4) and is approximately equal to direct burning after transport to the Midwest (option 3).

Disadvantages

- Population impacts in the West are substantially greater than for options that transport coal to the Midwest.
- Water consumption is large in an area that has limited water resources. With an increase of as much as 20 percent to the cost of electricity, dry cooling can be used to eliminate this disadvantage.
- Land use requirements, due to transmission corridors to the Midwest, are much larger than required for options that export coal from the West.
- NO_x emissions are high; in certain locations they can contribute to oxidant formation.

Option 2: Low-Btu gasification on-site; combined cycle electricity generation; transmission to Midwest

Advantages

- Ambient SO_2 levels are less than 25 percent of the direct coal burning levels (options 1 and 2).
- Ambient NO_x levels are less than 4 percent of levels from direct burning (options 1 and 3). The potential for photochemical oxidant formation is greatly reduced from that of the direct burning options.
- Particulate emissions and resulting ambient air levels are substantially smaller than for direct burning if advanced gasification technology is used.

Disadvantages

- Population impacts in the West are greater by a factor of ten or more than for options that transport coal to the Midwest (options 3 and 4) and greater by a factor of three than for direct burning on-site (option 1).
- Consumption of western water is the greatest of the four options.
- Land use impacts due to transmission corridors to the Midwest are large.

- Cost of electricity, on the basis of current low-Btu gasification technology, is significantly higher for gasification processes than for direct burning of coal.

Option 3: Coal transport to Midwest by rail; direct electricity generation

Advantages

- Urbanization impact on West is minimal.
- Consumptive use of water in the West is small.
- Land use impacts are reduced as present rail lines are substituted for new transmission lines.
- Cost of electricity is lower than for low-Btu gasification options.

Disadvantages

- SO_2 emissions are the highest of the options (2-1/2 times greater than on-site gasification). These emissions occur near heavily populated areas already subject to high levels of SO_2 and sulfates.
- NO_x emissions are high (approximately equal to comparison federal performance standards).
- Particulate emissions are high.

Option 4: Coal transport to Midwest by rail; low-Btu gasification; combined cycle electricity generation

Advantages

- Urbanization impact on West is minimal.
- Consumptive use of water in the West is small.
- SO_2 emissions are low.
- NO_x emissions are low; potential for formation of photochemical oxidants is low.
- Land use impacts are reduced.

Disadvantages

- Cost of electricity on the basis of current low-Btu gasification technology is significantly higher than for direct burning of coal.

2. Analysis of Critical Tradeoffs

The pro/con discussion has delineated the tradeoffs associated with the options to increase electricity generation. These are summarized in Figure II-1 below.

	SO_2 Impacts	NO_x Impacts	Particulate Impacts	Population Impacts	Aesthetic/Land Use	Water Consumption Rel. to Availability	Water Quality
1 Direct Burning in West	0	−	0	−	−	−	0
2 Combined Cycle in West	+	+	+	−	−	−	0
3 Direct Burning in Midwest	−	−	−	+	+	+	0
4 Combined Cycle in Midwest	+	0	0	+	+	+	0

+ = LEAST ADVERSE IMPACT 0 = INTERMEDIATE IMPACT − = MOST ADVERSE IMPACT

FIGURE II-1. ENVIRONMENTAL TRADEOFF MATRIX FOR OPTIONS TO INCREASE ELECTRICITY PRODUCTION FROM WESTERN COAL

Caution must be exercised in interpreting Figure II-1. It would be incorrect to conclude that the options with the smallest number of "most adverse" and the largest number of "least adverse" rankings are necessarily those that are most desirable from an environmental point of view. The reason for this is that (1) the relative importance of the different environmental impact categories has not been established in this

study (e.g., is a "most adverse" SO_2 ranking more or less important than a "most adverse" population impact ranking?) and (2) Figure II-1 does not consider the degree to which the environmental costs and benefits are equitably distributed among the population affected by the production of electricity. We have hitherto excluded these two factors from the analysis because they are both heavily laden with value judgments. We now include these subjective factors in the analysis of the two relative rankings among the four western coal options.

a. Establishing the "least adverse" option

We first analyze Figure II-1 to determine if any options exhibit dominance in the rankings relative to the remaining options. Dominance of rankings is achieved for option 4, combined cycle in the Midwest, which is ranked either "least adverse" or "intermediate" in impact for all impact categories. We thus establish a ranking independent of subjective values ascribed to the relative importance of the impact categories or to the issue of equity and conclude that

- Option 4, combined cycle in the Midwest, has the least adverse environmental impact of the four options.

b. Establishing the "most adverse" option

Option 1, direct burning in the West, has "most adverse" impacts for four categories and no "least adverse" impacts. Options 2 and 3 each have three "least adverse" and three "most adverse" impacts. It is possible to conclude that option 2, combined cycle in the West, is environmentally preferable to option 1, since they share equivalent "most adverse" rankings and option 2 is favored in each of the remaining categories (the air pollution impacts).

Comparison of options 1 and 3, siting steam electric power plants in the West and Midwest, respectively, is more difficult.

Population, aesthetic/land use, and water consumption impacts favor siting in the Midwest. Rankings for the impact of SO_2 and particulate emissions on human health favors siting in the West. Value judgments between adverse social impacts in the West and adverse health impacts in the Midwest are difficult to reach and are likely to be dependent on the person making the judgment. A more nearly equitable distribution between the costs and benefits of the electricity generation is achieved by siting in the Midwest, near the population benefiting from the electricity generation.

It is our tentative judgment that

- The siting of steam electric power plants in the Midwest (option 3) is environmentally preferable to the siting of steam electric power plants in the West (option 1).

This judgment is derived from equity considerations, which favor siting in the Midwest, as well as from the recognition that (1) population impacts are potentially able to cause substantial degradation in the quality of life in resource-rich areas of the West (see Volume IV, Chapter III) and (2) air pollution impacts in the Midwest might be controlled either by careful site selection or by reducing emissions from existing sources when new power plants are installed.

Additional analytical work is needed to subject this tentative judgment to critical evaluation. Such a study would compare the feasibility and cost of siting power plants in the Midwest so that air pollution health impacts are minimized with the feasibility and cost of reducing undesirable social impacts and minimizing water consumption of power plants in the West.

c. Differentiating among "intermediate" impact options

No attempt is made to rank option 2, combined cycle in the West, relative to option 3, direct burning in the Midwest. The tradeoff analysis establishes no dominance among the ranking categories between

the two options. Any choice among these options requires a heavy dose of value judgment. Resolution of the question of relative environmental cost of these two options probably requires that site-specific analyses be undertaken.

d. Recommendations

Based on the analysis of critical environmental tradeoffs among the four options to increase electricity production from western coal, we recommend that

- Research and development for low-Btu gasification/combined cycle operations is worthy of high-level effort because of the environmental benefits of the technology. A successful R&D program would strive to improve the efficiency of the low-Btu gasification/combined cycle operation to increase its commercial desirability.
- Additional analysis should be carried out to establish the feasibility and costs of siting power plants at distances from urban centers sufficient to substantially reduce urban impacts of air pollution. For cases in which western coal is an appropriate choice of fuel, these costs should be compared with the costs of reducing environmental and social pressures on the West.

REFERENCES AND NOTES FOR CHAPTER II

1. Effects of Coal Development in the Northern Great Plains, Northern Great Plains Resources Program (April 1975).

2. For a discussion of air pollution emissions and impacts, see Chapter VI of Volume IV.

3. Population and related social impacts of western coal development are discussed in Chapter III of Volume IV.

4. For a full discussion of the water availability in the upper Missouri Basin, see Section E, Chapter IV of Volume IV.

5. "Demonstrated Coal Reserve Base of the United States on January 1, 1974," U.S. Bureau of Mines (June 1974).

6. "Project Independence Report," Federal Energy Administration (November 1974).

7. "Rehabilitation Potential of Western Coal Lands," National Academy of Sciences (1974).

8. Cootner, P. H. and G. O. G. Lof, Water Demand for Steam Electric Generation, Resources for the Future, Inc. (1963).

9. See Chapter IX, Section C3 for the estimated water consumption of low-Btu gasification/combined cycle technology.

10. Townsend, S. and V. Laven, An Economic Analysis of Alternative Technologies for Cooling Electric-Thermal Generating Plants in the Fort Union Coal Region (1974).

III. EVALUATION OF ENVIRONMENTAL IMPACTS OF SELECTED OPTIONS FOR INCREASING U.S. OIL PRODUCTION

A. Introduction

This chapter analyzes the environmental tradeoffs associated with the following seven measures for increasing domestic oil production:

1. Liquefaction of midwestern coal in the Midwest
2. Liquefaction of western coal in the West
3. Production of synthetic crude oil from oil shale
4. Oil from the Outer Continental Shelf (Mid-Atlantic OCS)
5. Oil from onshore Alaska
6. Assisted recovery of oil--micellar flood and CO_2 miscible methods
7. Assisted recovery of oil--steam injection methods.

For all except options 4 and 5, we have assumed that crude oil is pumped to a location in the Midwest near the upper Mississippi River, where it is refined and distributed. For option 4, oil from the Outer Continental Shelf (OCS), we have assumed that the oil is produced from the mid-Atlantic OCS and refined nearby. For option 5, Alaskan onshore oil, we assume that the oil is shipped to the West Coast, where it is refined. Since we are concerned with relative environmental impacts of the options, the analysis considers only the difference of the impacts of the refineries at the three locations, the mid-Atlantic region for option 4, California for option 5, and the Midwest for options 1-3 and 6-7.

1. Technology Overview

We present a brief overview of the seven options, noting major features of the technologies, their stage of development, and the assumptions we have made to evaluate their environmental impacts. Chapter II in Volume IV of this report contains a more extensive discussion of these technologies.

a. Liquefaction of midwestern coal

Of the coal liquefaction technologies under development, a variant of the solvent extraction process is most likely to be commercial in the near term. In the solvent extraction process, crushed coal is dissolved in a process-derived solvent and subsequently hydrogenated at elevated temperatures and pressures. After separating unreacted solids, the resulting product is fractionated to recover the solvent, yielding a synthetic crude oil suitable for use as a refinery feedstock.

We report results for three solvent extraction processes that are likely to be commercial in the near term: the Pittsburgh and Midway direct hydrogenation process (called SRC for solvent refined coal), the Consolidation hydrogen donor solvent process (called CSF for Consol Synthetic Fuel), and the Hydrocarbon Research, Inc. process (H-Coal). These processes are expected to be 60 to 65 percent efficient in converting coal to crude oil. The principal differences among these technologies are:

- The H-Coal process uses a cobalt-molybdenum catalyst in the hydrogenation process. SRC and CSF do not use a catalyst.
- The CSF process first extracts organic matter from the coal at relatively low pressure. The organic matter is then hydrogenated at high temperatures and pressures. SRC and H-Coal combine the extraction and hydrogenation processes.

- The SRC process hydrogenates the coal in two steps. The first step, which combines the extraction of organic matter and hydrogenation at low pressure, yields an intermediate solid product which can be further hydrogenated at higher pressure to yield a synthetic crude. H-Coal and CSF hydrogenate in one step.

The major incentive for developing coal liquefaction is the increased utility and flexibility of synthetic oil compared with that of coal in meeting U.S. energy demand. By converting high-sulfur coal to a low-sulfur crude, coal liquefaction has the promise of greatly expanding the limited U.S. supplies of low-sulfur petroleum products which can be burned without causing air pollution in excess of emission standards. The major limitation to rapid growth of coal liquefaction technology is economic: production of oil from coal is estimated to be 10 to 25 percent more costly than the present market value of new oil. It is not likely that coal liquefaction technologies will produce oil competitive with most other sources within the next decade or longer. Because only small-scale pilot plants have been built, many of the estimates of environmental impacts are only approximate.

To calculate impacts of liquefaction of midwestern coal, we have assumed the use of an average midwestern coal of 22 million Btu per ton, with a sulfur content of 3.5 percent and an ash content of 11 percent.

b. Liquefaction of western coal

The solvent refining processes used to liquify midwestern coal are suited for liquefaction of western coal, with only minor modification. We have assumed the use of coal from the Powder River Basin area of Montana and Wyoming, consisting of 0.8 percent sulfur, 8.3 percent ash, and 18 million Btu per ton.

c. Oil shale

Vast deposits of shale rock containing kerogen exist in Colorado, Utah, and Wyoming. Retorting processes, of which the most fully developed are the TOSCO II and Paraho designs, enable the kerogen to be extracted and upgraded into a crude oil. The TOSCO II retorting process heats the shale in a closed vessel through the introduction of hot ceramic balls. The Paraho process combusts organic matter in the shale to provide heat for retorting. The Paraho process has substantially lower capital and operating costs than TOSCO II; TOSCO II recovers a significantly higher percentage of the energy content of the shale than does Paraho. All of the oil shale retorting processes yield a solid residue of high salinity, which is greater in volume than the original shale rock. Present plans call for disposing of the spent shale residue in canyons near the mining site.

d. Oil from the Outer Continental Shelf

The technology for tapping oil resources in the OCS, consisting of the use of ships for geological exploration, exploratory drilling from one of several types of temporary platforms, use of fixed platforms for field development and production, and pipelines (or, occasionally, tankers) to transport the oil to shore, is well-developed and extensively used throughout the world. One major emphasis of present research is the development of techniques to drill in deeper waters. Research on methods of OCS drilling less potentially degrading to the environment has progressed since the Santa Barbara blowout in 1969; nonetheless, exploration and drilling activities in deep waters and in areas characterized by severe weather conditions are recent developments for which insufficient experience exists to estimate the effect of OCS operations.

e. Oil from onshore Alaska

We have assumed that the North Slope and Naval Petroleum Reserve 4 (NPR 4) are further exploited, necessitating a pipeline from NPR 4 to the trans-Alaska pipeline and an additional pipeline along the trans-Alaska pipeline corridor with a capacity of 2-1/2 million barrels per day. This assumption is consistent with Project Independence assessment of the onshore areas of Alaska most likely to be further developed.[1]

The technology used to drill for oil is well-established. Two features of the north Alaskan environment, however, make implementation of the technology more difficult than in other areas: the thick layer of permafrost north of the Brooks Range necessitates refrigeration of the drilling platform to avoid instabilities that occur if the permafrost is melted; the great depth of oil-bearing regions in Alaska (10,000 feet versus an average of 5000 feet in the lower 48 states)[2] further increases the need for structural stability in the drilling rigs and platforms. Technology is available to cope with these problems; however, the cost of drilling is higher in Alaska than in other regions.

f. Assisted recovery of oil--miscible methods

Advanced or assisted recovery methods for extracting more than the approximately 30 percent of oil presently removed from U.S. wells hold the promise of doubling onshore oil reserves in the lower 48 states.[3] The traditional method of assisted recovery of oil is waterflooding--the injection of water under high pressure into existing wells to increase the reservoir pressure. In a waterflood there exists a sharp boundary or interface between the oil and the water phases because of the lack of miscibility of the two phases; this fact and the different viscosities for the two fluids often lead to a channelling of the driving water through the oil or around it with concomitant loss of sweep efficiency for the driving fluid. The various miscible methods (hydrocarbon miscible and

water miscible) replace the sharp fluid boundary by a zone in which the oil and drive fluid mix; this causes better cleanout of the volume swept.

Micellar flood is the miscible technique likely to be most promising for advanced recovery operation in the United States.[4] With the micellar flood method, the slug is a surfactant solution, which forms a micellar fluid (a microemulsion) with the contacted oil. Petroleum sulfonates are commonly used as the surfactant and the driving fluid is a dilute polymer solution (polysaccharide or polyacrylamide).

The micellar flood method will see most application in Texas oil wells; projects in Oklahoma, Illinois, Pennsylvania, Colorado, Wyoming, and a few other locations are also planned. CO_2 and hydrocarbon miscible methods are anticipated in Texas and to a lesser degree in California, Wyoming, Oklahoma, and a few other areas.[5] Current research and development activities related to advanced recovery techniques are discussed in Volume IV, Chapter II, Section B4.

g. Assisted recovery of oil--steam injection

Steam injection and other thermal recovery methods, such as in-situ combustion, are primarily useful for very viscous oil, since higher temperatures can significantly lower the oil viscosity and thereby yield large production increases. Injection of hot water into the reservoir is the simplest thermal method, but it has not found wide application and probably has limited potential. Steam injection is a more effective technique since it carries far more heat content due to the higher temperature and the large heat of condensation of steam. Steam injection is expected to be widely used in California; in-situ combustion is planned for a number of wells in California and for a few wells in Texas, Louisiana, and Oklahoma.[5]

2. Energy Supply Potential of Options

The potential of any new energy technology to contribute to the nation's energy supply is determined by both the total available quantity of the resource on which the technology is based and the rate at which the technology can be developed and the resource exploited. While the quantity of resource in the ground places a physical upper limit on the total contribution to the nation's energy supply, the rate of development determines the contribution in any given year, and is determined largely by social, economic, and political factors, as well as by physical limitations.

To aid in achieving some insight into the relative contributions of the seven crude oil supply options analyzed in this chapter, the two following tables are presented. Table III-1 shows recent estimates of in-place reserves recoverable at current energy prices and with current technology.* In the case of the coal liquefaction options, the estimates are based on coal reserves. Since the estimates are based on current prices and extraction technology, it is possible that many of the reserve estimates will increase with time. In some cases (e.g., Atlantic OCS oil), further exploration could also significantly change the estimates.

Table III-2 illustrates possible levels of development for each crude oil supply source in 1980 and 1990. These estimates were derived from scenarios presented in the Project Independence Blueprint report and associated task force reports. The "high" and "low" development cases generally correspond to the Project Independence "accelerated development" and "business as usual" scenarios, respectively.

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*Note that the recoverable reserve figures are based on current prices and technology for extraction; at present, because of high costs of conversion to crude oil, the three synthetic oil options (1, 2, and 3) are not economically competitive.

Table III-1

AVAILABILITY OF RESOURCES FOR OPTIONS
TO INCREASE CRUDE OIL SUPPLY

Option	Estimated Recoverable Reserves (billion barrels)	Years of Supply at Present Consumption Level
1. Liquefaction of[a] midwestern coal	110	18
2. Liquefaction of[b] western coal	90	15
3. Oil shale[c]	240	39
4. Atlantic[d] OCS oil	3	0.5
5. Onshore Alaskan[d] oil	28	4.5
6. Assisted recovery[e] --miscible methods	25	4.0
7. Assisted recovery[e] --steam injection	10	1.6

[a] Based on conversion of 25 percent of underground and 50 percent of surface reserves at 3 barrels per ton. Coal reserves from Reference 6.

[b] Based on conversion of 50 percent of surface reserves at 2.5 barrels per ton. Coal reserves from Reference 6.

[c] Includes reserves of 25 gal/ton and greater. Reference 7.

[d] Most recent USGS estimates. Reference 8.

[e] Reference 9.

Table III-2

POSSIBLE DEVELOPMENT SCHEDULES FOR CRUDE OIL PRODUCTION
(millions of barrels per day)

Source		1980	1990
Coal liquefaction[a]	High	0	2
	Low	0	0.2
Oil shale[b]	High	0.1	1.6
	Low	0.05	0.5
Atlantic OCS[c]	High	0.14	0.9
	Low	0	0.15
Onshore Alaska[d]	High	0	2
	Low	0	0
Assisted recovery[c]	High	1.2	3.5
	Low	0.9	2.7

[a] Derived from Reference 15.

[b] Derived from Reference 7.

[c] Derived from Reference 10.

[d] Development in addition to current and planned North Slope production, Reference 10.

The development schedules displayed in Table III-2 should not be taken as predictions of the future, but rather as estimates of the levels of production that could be achieved under certain conditions.

As the quantities in Tables III-1 and III-2 indicate, oil shale and coal liquefaction have the potential for making the greatest contribution to the nation's long-term oil supplies, and are expected to contribute significantly by the late 1980s. In the near term, assisted recovery of oil from existing fields can provide the most substantial contribution. However, utilization of this method at the high levels anticipated for 1990 would rapidly exhaust the available resource.

B. Conclusions

Based on the analysis of environmental impacts presented in this chapter, we have concluded that the use of micellar flood and other miscible techniques of assisted recovery pose the least adverse environmental risks of the seven options for increasing domestic oil production. Advanced recovery methods using steam injection have the potential for low environmental impact if air pollution resulting from the generation of steam is adequately controlled. The production of crude oil from oil shale using the TOSCO II process has the potential for causing the greatest environmental degradation of the options considered. Although recent information indicates that methods may be employed to reduce some air pollutant emissions, nonetheless, a broad range of adverse impacts may be anticipated from the development of a large oil shale industry.

The ranking of the other options was found to be strongly dependent on the relative importance attached to oil spills as a source of environmental degradation. If oil spills are judged to have only a limited impact from which recovery occurs in a short time through natural processes, then oil from the OCS and Alaska is probably preferable to liquefaction of midwestern coal, which is in turn favored over liquefaction of western coal in the West. If oil spills are judged to be of significant and lasting import, then the liquefaction options would be judged preferable to the options that produce oil from the OCS and Alaska.

An important determinant in the ranking was found to be the relative importance ascribed to the adverse social impacts due to rapidly populating a wilderness area or a region that previously supported only a limited population. If this impact is judged preeminent, then the favored options are liquefaction of midwestern coal and oil from the OCS. Liquefaction of coal in the West and oil from Alaska are then judged the least desirable of the remaining options.

An attempt to distribute the environmental cost among the beneficiaries of energy development would also tend to favor liquefaction of midwestern coal and oil from the OCS over oil shale, western coal liquefaction, and oil from Alaska.

C. Analysis of Environmental and Social Impacts of Options to Increase U.S. Oil Production

We present a summary analysis of the relative impacts of the seven methods for increasing U.S. oil production. If the difference in impacts among the options appear not greater than about 25 percent by the quantitative measures employed, we have ranked them equal. We have also not differentiated impacts among the options if the information base to do so was judged inadequate.

1. SO_2 Impacts on Air Quality

Most probable estimates for SO_2 emissions are shown in Table III-3. The complete discussion of the assumptions required to estimate emissions for the coal liquefaction and oil shale processes is contained in Volume IV, Chapter VI, Section C. Here we note that the SO_2 emissions from coal liquefaction and oil shale processing result primarily from plant fuel combustion to provide process heat and electrical power, and also from sulfur recovery units (especially for coal liquefaction). The removal efficiency for coal burning is assumed to be 85 percent. SO_2 emissions from oil shale are greater than from coal liquefaction in large measure because the oil shale process designs rely on hydrotreating the fuel oil to reduce NO_x and SO_2 while coal liquefaction designs incorporate scrubbers. Additional hydrotreating of the fuel oil could lower SO_2 emissions from oil shale. The level of emissions from coal liquefaction is strongly dependent on the choice of technologies as well as on the type of coal burned. The somewhat surprising result that the H-Coal process emits more SO_2 using low-sulfur western coal than high-sulfur midwestern coal

Table III-3

SO_2 EMISSIONS FROM OIL PRODUCTION OPTIONS [16]

Option	SO_2 Emissions (tons/10^{12} Btu crude oil output)
Coal liquefaction (midwestern coal)	
a. H-Coal*	55
b. CSF	70
c. SRC	76
Coal liquefaction (western coal)	
a. H-Coal*	63
b. CSF	38
c. SRC	20
Oil shale	
a. TOSCO II*	98-120
b. Paraho	70†
c. In-situ	100†
OCS oil	negligible
Onshore Alaskan oil	0.5
Assisted recovery (surfactant and CO_2 miscible)	negligible
Assisted recovery (steam injection)	280-560

*The rankings at the end of the section are for these processes, that are judged most likely to be widely used for the production of crude oil.

†Denotes large uncertainty in estimate.

is due to primarily the larger quantity of process-derived residual tars, which can be gasified and used in the hydrogenation of midwestern coal.

The results of the model calculations of ambient air quality as shown in Table III-4 indicate that federal secondary air quality standards will not be exceeded by SO_2 emissions from a single 100,000 barrel-per-day oil shale plant.[11] However, federal Class I standards will be exceeded, and a significant fraction of the Class II standards are attained. Federal secondary and Class II standards could be exceeded if emissions from more than one plant were considered. Liquefaction of western or midwestern coal can also cause the most stringent standard to be exceeded, although ambient air concentrations of SO_2 are generally less than for oil shale processing. The liquefaction of western coal has somewhat less impact on SO_2 concentrations in the air than does the liquefaction of midwestern coal.

SO_2 emissions shown for the steam injection technique are based on uncontrolled emissions from burning fuel oil or crude to produce steam. The lower estimate is for oil of 1 percent sulfur; the higher is for oil containing 2 percent sulfur. The emissions could be substantially reduced if scrubbers were used to remove SO_2 from stack gas emissions. However, on the basis of interviews conducted with private industry, we have concluded that industry is not currently planning to employ abatement technology. Uncontrolled emissions of this level could exceed ambient air quality standards in regions for which the ambient air is already degraded. This is likely to occur, for example, in the San Joaquin Valley of California, if steam injection techniques are employed and emissions are not controlled.

The low level of SO_2 emissions associated with onshore Alaskan oil is due to the pumps used to drive the oil through the Alaskan pipeline.[12] SO_2 emissions from the surfactant and CO_2 miscible techniques for tertiary recovery of oil and from OCS oil are negligible.

Table III-4

SO_2 IMPACTS ON AIR QUALITY NEAR A 100,000 BBL/DAY CRUDE OIL PRODUCTION FACILITY

SO_2 Concentration/Ambient Air Quality Standard

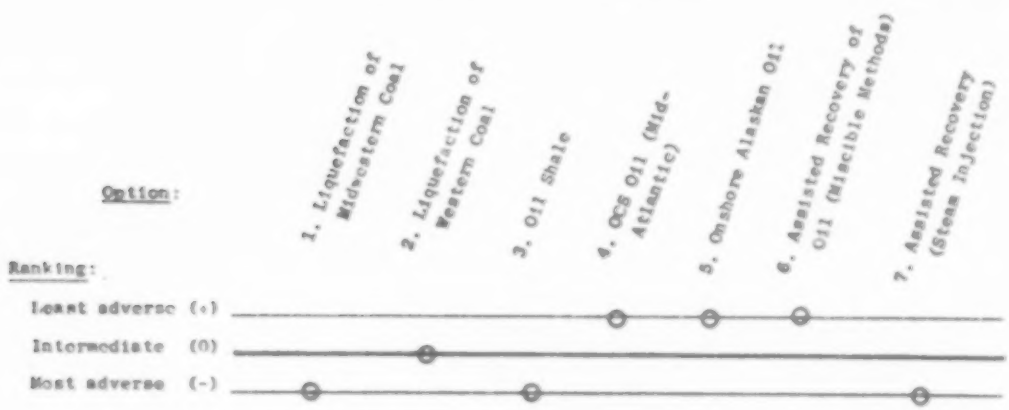
Option	3 hr (Worst Case)			24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I	Class III	Class II	Class I
1. Midwestern coal* liquefaction	0.01-0.14	0.19-0.26	5.1-7.0	0.10-0.14	0.26-0.36	5.4-7.5	0.04-0.06	0.16-0.24	1.3-1.8
2. Western coal* liquefaction	0.04-0.14	0.07-0.26	2.3-7.4	0.05-0.16	0.13-0.42	2.6-8.2	0.02-0.05	0.08-0.20	0.51-1.6
3. Oil shale†	0.17-0.22	0.32-0.41	8.7-11	0.16-0.21	0.42-0.55	8.4-11	0.06-0.08	0.24-0.32	1.9-2.5
4. OCS oil					Negligible				
5. Alaskan oil					Negligible				
6. Assisted recovery (miscible methods)					Negligible				
7. Assisted recovery (steam injection)					Significant but not quantified				

*H-Coal process.

†TOSCO II process.

The impacts judged "most adverse" were those for liquefaction of midwestern coal, because the emissions are likely to affect populated areas already suffering from high levels of air pollution, and those for oil shale and steam injection, because of the magnitude of the ambient air concentrations compared to the standards. The rankings are subject to change if more stringent air pollution control measures are applied to the processes.

Rankings for SO_2 Impacts



2. Particulate Impacts on Air Quality

Particulate emissions from the seven options for increasing domestic oil supply are shown in Table III-5, and the impacts on air quality are shown in Table III-6. These tables indicate that for assisted recovery of oil (miscible methods), OCS oil, and onshore Alaskan oil, particulate emissions are low, impacting air quality in only limited measure.

Particulate emissions from liquefaction of western and midwestern coal are comparable, as shown in Tables III-5 and III-6. For the 24-hour worst case example, Class I air quality standards could be slightly exceeded by one 100,000 barrel-per-day coal liquefaction plant using either western or midwestern coal, according to model calculations.

Table III-5

PARTICULATE EMISSIONS FROM OIL PRODUCTION OPTIONS[11]

Option	Particulate Emissions in Tons per 10^{12} Btu Crude Oil Output
Coal liquefaction (midwestern coal)	
a. H-Coal*	9
b. CSF	6
c. SRC	5
Coal liquefaction (western coal)	
a. H-Coal*	13
b. CSF	7
c. SRC	5
Oil shale	
a. TOSCO II*	35-47
b. Paraho	15†
c. In-situ	20†
OCS oil	negligible
Onshore Alaskan oil	negligible
Assisted recovery (miscible methods)	<1.
Assisted recovery (steam injection)	41

*Processes which are judged most likely to be widely used for the production of crude oil.

†Denotes large uncertainty in estimate.

Table III-6

PARTICULATE IMPACTS ON AIR QUALITY NEAR A 100,000 BBL/DAY CRUDE OIL PRODUCTION FACILITY

Particulate Concentration/Ambient Air Quality Standard

Option	24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I
1. Midwestern coal* liquefaction	0.04-0.07	0.20-0.37	0.61-1.1	0.005-0.01	0.04-0.07	0.07-0.13
2. Western coal* liquefaction	0.03-0.08	0.15-0.40	0.46-1.2	0.08-0.02	0.04-0.09	0.07-0.18
3. Oil shale†	0.21-0.29	1.1-1.5	3.2-4.4	0.04-0.06	0.26-0.36	0.52-0.72
4. OCS oil			Negligible			
5. Alaskan oil			Negligible			
6. Assisted recovery (miscible methods)			Negligible			
7. Assisted recovery (steam injection)			Significant, but not quantified			

*H-Coal process.

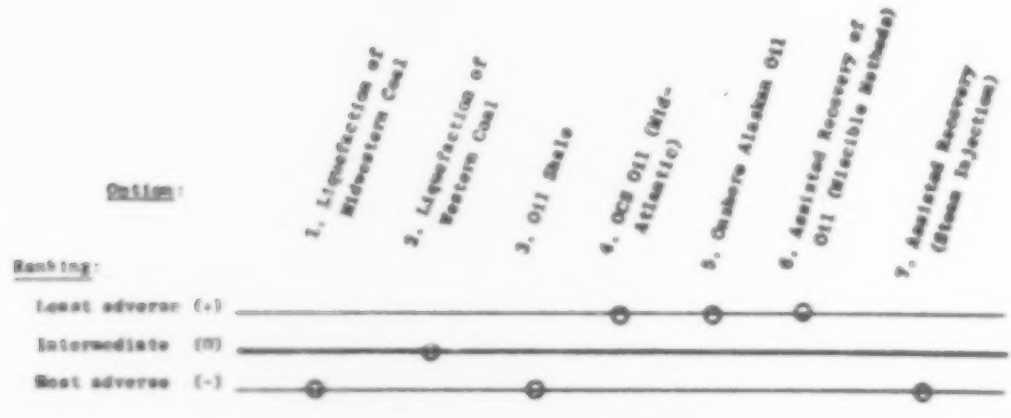
†TOSCO II process.

To calculate oil shale emissions for the TOSCO II process, we have used data from Colony Development Operation, which were based on the use of scrubbers and fabric filters.[13] The particulate emissions from oil shale retorting and upgrading are greater than those from coal liquefaction, and a 100,000 barrel-per-day oil shale plant using TOSCO II processes can exceed ambient air quality standards for Class I and Class II regions.

Particulate emissions from steam injection oil recovery are calculated on the assumption that no control technology is used to reduce these emissions significantly. These emissions are approximately the same as for oil shale. The effect on air quality is probably similar to that of oil shale as well, since neither process uses high stacks to disperse the particulate emissions.

We have ranked oil shale and assisted recovery particulate emissions "most adverse," because of the possible violation of Classes I and II air quality standards. Coal liquefaction, which may violate the Class I standards, is also ranked "most adverse," because the emissions are likely to affect populated areas. Liquefaction of western coal is ranked "intermediate" and the other processes receive a "least adverse" ranking.

Rankings for Particulate Impacts



3. NO_x Impacts on Air Quality

Table III-7 lists the NO_x emissions from the options. NO_x emissions from coal liquefaction depend on the process used and on the choice of fuel to supply steam and heat for the liquefaction process. To the extent that gases derived from the liquefaction are used to provide process heat, NO_x emissions are reduced. The lower level of NO_x emissions for liquefaction of midwestern coal by the H-Coal process is explained by the fact that more process-derived gases are obtained using midwestern rather than western coal.

The high emissions of NO_x for a TOSCO II oil shale plant are due to the use of fuel oil derived from oil shale, which has a high nitrogen content, to partially meet its fuel requirements. The combustion of this fuel oil to generate steam and heat for plant use results in an NO_x emission 10 times higher than would be obtained if natural gas were combusted. Additional hydrotreating of the fuel oil could reduce NO_x emissions significantly, as reflected in the lower of the two emission estimates for oil shale in Table III-7. On the basis of model calculations, the results of which are shown in Table III-8, federal primary air quality guidelines for NO_x would not be exceeded for a single 100,000 barrel-per-day oil shale plant even under unfavorable weather conditions.[14]

Assuming that the H-Coal process is used for coal liquefaction, the ambient concentrations of NO_x are almost four times as great for western coal as for midwestern coal. The use of different liquefaction technologies could change this relative rating somewhat.

NO_x emissions from steam injection are caused by the combustion of oil to generate steam. By controlling the combustion process carefully, they could be reduced somewhat. Ambient air concentrations have not been calculated, but are expected to scale roughly as the level of emissions. The small NO_x emissions for Alaskan onshore oil are due to the pumping stations along the oil pipeline.

Table III-7

NO_x EMISSIONS FROM OIL PRODUCTION OPTIONS

Option	NO_x Emissions in Tons per 10^{12} Btu Crude Oil Input
Coal liquefaction (midwestern coal)	
a. H-Coal*	44
b. CSF	61
c. SRC	66
Coal liquefaction (western coal)	
a. H-Coal*	160
b. CSF	65
c. SRC	66
Oil shale	
a. TOSCO II*	85-280
b. Paraho	30†
c. In-situ	40†
OCS oil	negligible
Onshore Alaskan oil	1.5
Assisted recovery (miscible methods)	negligible
Assisted recovery (steam injection)	110

*Processes which are judged most likely to be widely used for the production of crude oil.

†Denotes large uncertainty in estimate.

Table III-8

NO_x IMPACTS ON AIR QUALITY NEAR A 100,000 BBL/DAY CRUDE OIL PRODUCTION FACILITY

NO_x Concentration/Ambient Air Quality Guideline

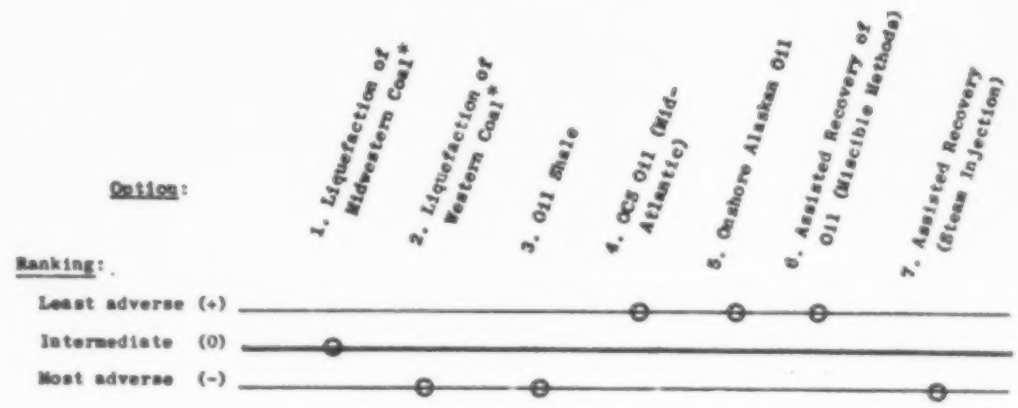
Option	Annual Average
1. Midwestern coal* liquefaction	0.01-0.02
2. Western coal* liquefaction	0.008-0.02
3. Oil shale†	0.03-0.17
4. OCS oil	Negligible
5. Alaskan oil	Negligible
6. Assisted recovery (miscible methods)	Negligible
7. Assisted recovery (steam injection)	Significant, but not quantified

*H-Coal process.

†TOSCO II process.

The relative impacts of NO_x of air quality generally follow the emissions in Table III-7. A more refined analysis of these NO_x impacts, well beyond the scope of this study, would investigate the potential for photochemical smog formation in the different regions where processing emits NO_x.

Rankings for NO_x Impacts



4. Population and Related Social Impacts

A rapid influx of people into a locality or region extending in time over years or decades can lead to serious, undesirable social impacts. The degree of the impact is largely determined by the rate of growth of the population, the degree of planning done in anticipation of the "boom," and the ability of the existing political and economic institutions to absorb the new population and provide for its needs. Past experience with boom-bust situations suggests that relatively undeveloped and sparsely populated areas are most likely to suffer adverse social impacts from large population influxes.

To evaluate impacts of coal liquefaction, we note that the accelerated development scenario of Project Independence estimates more than one quadrillion Btu of synthetic liquids from coal by 1985 and three quadrillion Btu by 1990.[15] This corresponds to a permanent population increase in localities near coal liquefaction sites of as much as 100,000

in 1985 and 300,000 in 1990.* In addition, an increase in the temporary construction labor force and associated population of an equal magnitude during the years of active growth of the industry may be expected.[16]

Liquefaction of coal in the West can be expected to take place in the coal-bearing regions: the Powder River Basin, the Four Corners Area, and possibly North Dakota. All of these areas are presently rural and relatively undeveloped. The coal-bearing regions of Montana, Wyoming, and North Dakota, for example, presently contain approximately 400,000 inhabitants.[17] An influx of half a million people in a short time into these regions will cause very rapid population growth rates in many localities, putting an enormous strain on the social fabric and resources of the localities impacted. If coal gasification and generation of electricity for export also take place in the western coal regions, then the pressures of rapid population growth will be greatly magnified.

The social impact of liquefying midwestern coal, on the other hand, is expected to be small in most cases, since the liquefaction plants are assumed to be sited near industrial areas in the Midwest, which can absorb the additional population. To the extent that the work force consists of previously unemployed workers, population pressures are further diminished.

Oil shale development will take place in a limited number of regions of concentrated shale deposits. These regions are presently undeveloped, consisting of small towns and rural or wilderness areas. The counties of Mesa, Garfield, and Rio Blanco in Colorado are expected

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*These estimates are appropriate for extensive development in rural areas, in which services for the new workers and their families are expected to expand greatly. If liquefaction takes place near predominantly urban areas, the total population increase in the impacted localities is estimated to be about half as great as the numbers quoted.

to be the most intensively developed of the oil shale lands. The present population of towns adjacent to Colorado oil shale regions is about 50,000, of which 34,000 is concentrated in the Grand Junction area. For an oil shale industry producing 10^{15} Btu per year (approximately five 100,000 barrel-per-day plants and 50 percent of the Project Independence accelerated development scenario for 1985), the anticipated number of permanent new residents--oil shale workers, their families, and persons drawn into the area by associated industries and services--is between 50,000 and 100,000. Thus, the permanent population in the three-county area is expected to at least double during the coming 10-year period. Including construction workers and associated population, the peak population could be treble present levels in just a decade. As noted, past experience has shown that the social, political, and economic problems in localized rural areas are likely to be severe when population growth is so rapid.[17]

Producing oil from the mid-Atlantic OCS and refining it onshore is somewhat less labor intensive than coal liquefaction in the West or oil shale mining and retorting. It is also expected to occur near a populated area. The CEQ report, OCS Oil and Gas--An Environmental Assessment, projects a net population increase of approximately 100,000 for activities producing 10^{15} Btu per year for a combined oil and gas OCS development (80 percent oil, 20 percent gas).[18]* An important finding of the CEQ report is that social impacts for OCS development are highly sensitive to refinery location. The report concluded, for example, that Jacksonville, Florida, could accommodate a substantial population increase much more readily than Charleston, South Carolina.[18]

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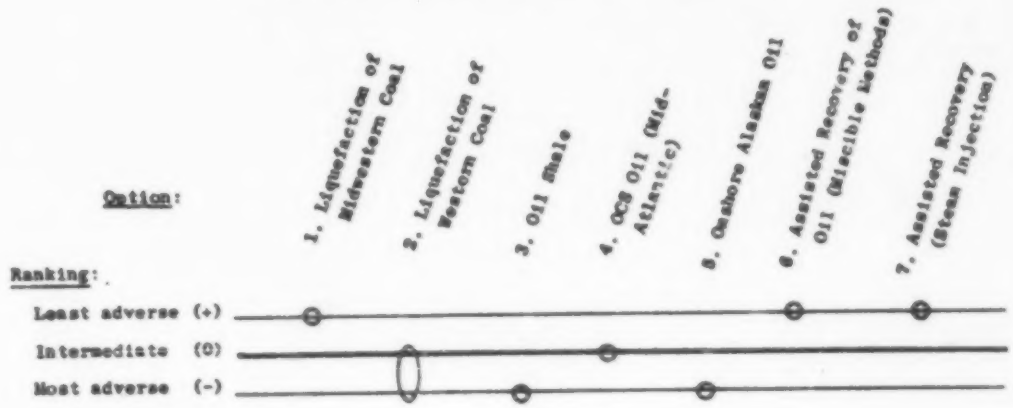
*Somewhat less than one-third of this population increase is related to employment at the refinery. We have not included refinery workers and their associated population in our assessment of the other options, for which the refinery is not located near the site of resource development.

Social impacts in Alaska of onshore development are likely to be severe. Based on national averages for the number of workers employed in oil and gas production and a standard estimate of the size of workers' families and the number of persons in associated industries and services, a population increase of between 20,000 and 40,000 per 10^{15} Btu can be expected.[19] This corresponds to between 100,000 and 200,000 additional people in Alaska to support an increased oil production of 2-1/2 million barrels per day needed to keep a second pipeline working at capacity. When this figure is compared to the 1972 Alaskan population of 325,000 and the additional population needed to support the first pipeline is taken into consideration, it is apparent that the population pressures on Alaska will be very large.

Assisted recovery of oil in existing oil fields will have only a short-lived social impact in most areas for which it is planned; this impact is due to the construction crew needed to drill additional wells and build associated rigs. Once drilling and construction are completed, the remaining work force to carry out operations is small.

Our judgment regarding expected social impacts of the seven options is shown below. The entry for liquefaction of western coal spans the intermediate and adverse impact categories, reflecting our judgment that its impact need not be so serious as that of oil shale and Alaskan oil because of the area of western coal over which the population could be spread. The great expanse of the coal resources in the West allows more flexibility in planning activities and the selection of mining and liquefaction sites. However, the changes induced by increased population have the potential of permanently impacting a significant number of localities in the West.

Rankings for Population Impacts



5. Water Consumption Relative to Availability

The quantities of water required by the different methods of augmenting oil supply are shown in Table III-9. The estimates for a given technology will vary by approximately ± 20 percent.

It is not the absolute magnitude of water consumption that differentiates among the options, but rather the availability of water resources in the region to be developed. Ample water supplies are available for coal liquefaction in the Midwest and for assisted recovery using micellar solution and CO_2 miscible techniques near most existing U.S. oil fields.

Because steam injection methods of assisted recovery require large quantities of water, they will be limited to regions with adequate water supplies or will require that the water be imported. In areas such as the San Joaquin Valley in California, for which steam injection or an alternative thermal method is required to enhance recovery of the high viscosity oil, demands on water supply could be severe.

Table III-9

WATER CONSUMPTION TO PRODUCE CRUDE OIL

Option	Water Consumption (thousand acre-feet/10^{15} Btu crude oil output)
Coal liquefaction	130[a]
Oil shale	80[b]
OCS oil	negligible
Alaskan oil	negligible
Assisted recovery (surfactant and CO_2 miscible)	25-50[c]
Assisted recovery (steam injection)	130-165[d]

[a] Reference 20.

[b] Reference 21.

[c] Reference 22.

[d] Reference 23.

The water requirements for oil shale and liquefaction of western coal pose substantial problems. The Colorado River Basin is the source of water for the majority of proposed oil shale projects. Of the estimated 5.8 million acre-feet of water flow available for consumption in the Colorado River Basin in an average year, approximately 2 million acre-feet are presently unused. The extent to which use of this water will threaten aquatic life by diminishing instream flows is not precisely known, but the adverse effects could be significant.[24] Projections for growth in non-energy uses of the water, coupled with development of oil shale, indicate a level of demand in excess of supply by the late 1980s or early 1990s.

Coal liquefaction in the West presents equally serious problems regarding water consumption. We have assumed that liquefaction will occur predominantly in the upper Missouri River Basin. The water requirements

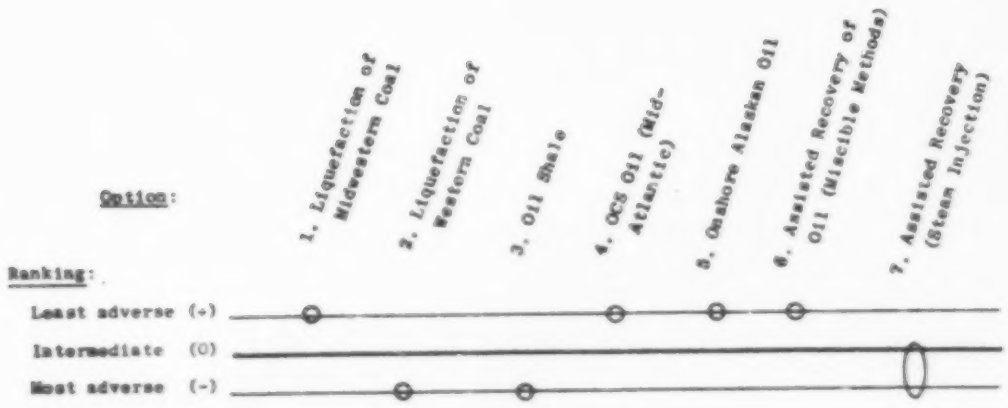
for coal liquefaction, other projected coal conversion activities, and agricultural uses are likely to threaten instream flows by the early or mid-1980s, if present growth plans are realized.[24]

Future water requirements for oil shale and coal liquefaction in the West can be met in one of three ways:

- Massive interbasin transfers of water, requiring aqueduct systems and additional reservoirs
- Limiting growth of agricultural uses of water
- Failure to protect aquatic life in the Missouri and Colorado Rivers.

We rate the impacts of the seven options in the figure below.

Rankings for Water Consumption
Relative to Availability Impacts



6. Land Use

Land use impacts are judged least adverse for assisted oil recovery because the technique affects land which is already devoted to oil recovery operations. The major impact is a substantial increase in the number of wells in oil fields; in general, both exploratory wells and injection wells are required in significant number.

For coal liquefaction in the Midwest, land is devoted to the mining of coal, waste disposal, and processing facilities. Assuming strip mining of the land in the Midwest, about 20 acres are disturbed in order to produce 10^{12} Btu of coal-derived liquids.[25] If proper reclamation techniques are applied, reclamation should be possible within three to five years. Neither waste disposal, if properly handled, nor the siting of the coal liquefaction plant is likely to impact the land as much as the mining.

For coal liquefaction in the West, the most serious land impacts are also those associated with strip mining of the coal. Because of the thicker coal seams in the West, only about 15 percent as much land need be disturbed as in the Midwest to produce an equal quantity of coal: on the average, 2 acres in Wyoming and 3.8 acres in Montana per 10^{12} Btu of coal-derived liquids.[26] However, at most sites, rehabilitation of land in the West is considerably more difficult than rehabilitation of land in the Midwest, due to the infrequent rainfall and fragile ecosystem prevailing throughout the West. Only if careful site selection, preplanning, and proper reclamation practices are observed is the rehabilitation in the West relatively high.

For oil shale, the land directly disturbed by mining, processing, and shale disposal, is significantly less than that disturbed by coal mining for liquefaction: per 10^{12} Btu, about 0.35 acres are devoted to mining; 0.75 to shale disposal; 1 to 2 acres to on- and offsite processing facilities.[21] This is to be contrasted with 20 acres for strip mining

midwestern coal. Nonetheless, land impacts associated with oil shale appear to be the more severe because:

(a) Strip-mined land in the Midwest can be rehabilitated, if proper techniques are used to select and revegetate the land.

(b) The likelihood of returning the canyons which have been filled with spent shale to a state which can sustain vegetation without constant fertilization and irrigation is as yet unknown. Even if revegetation proves possible, the canyon will be destroyed.

An additional consideration of importance to both oil shale and liquefaction of western coal is the land which is needed for new pipelines to carry upgraded shale oil to refining facilities.

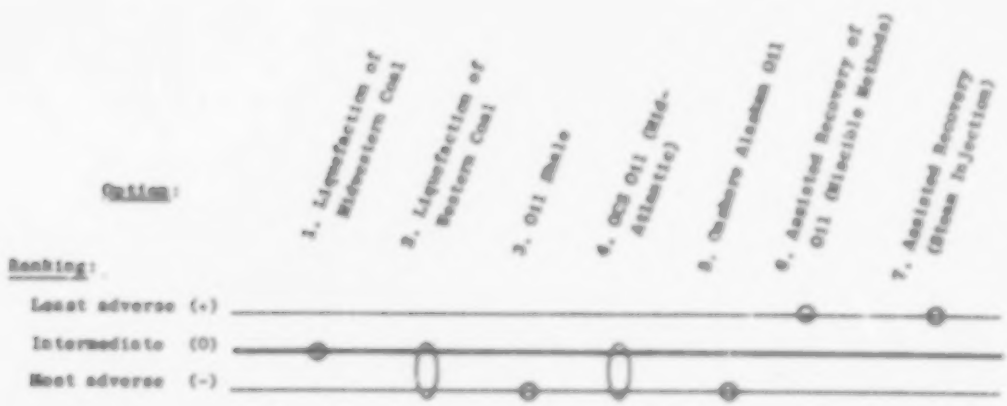
Land use impacts of OCS oil development are difficult to evaluate in the abstract. All of the options require refineries to process crude oil. OCS oil results in a refinery cited in or near a coastal zone, and thus has impacts qualitatively different from those of the other options. Coastal lands tend to be high priority areas for recreational uses and nature preserves. In coastal areas already devoted to industrial activity, the aesthetic and land use impacts of a new refinery is likely to be judged less severe than those in a less developed area. An added adverse land use impact of OCS oil will occur if oil pipelines are permitted to traverse wetlands, where the dredging and spoil activities can degrade the biological diversity and productivity of the area.

For oil from onshore Alaska, the land use impacts are primarily those associated with the construction of new oil pipelines in Alaska. We have assumed that Naval Petroleum Reserve 4 (NPR 4) is the source of the additional oil capacity. Development of NPR 4 will require a pipeline of approximately 200 miles to join the trans-Alaska pipeline. The pipeline would presumably be built north of the Brooks Range in northern Alaska. As such, it would traverse an area underlain by thick permafrost, dotted

by large numbers of small lakes, and lined with streams. A pipeline in this area can cause local melting of the permafrost, interference with migratory patterns of wildlife, disturbance to streams, and undesirable aesthetic impacts. Additionally, an accident which causes a break in the pipeline could result in oil spills on ice. The effect of such spills is not known, although there has been speculation that the oil could cause large areas of ice to melt.[27]

On the basis of the above considerations, we judge the relative land use impacts as shown below. The ambiguity in the evaluation of coal liquefaction impacts derives from uncertainty regarding the enforcement of adequate rehabilitation standards of western coal land. For OCS oil, the impact depends on the specific siting of the refinery.

Rankings for Land Use Impacts



7. Water Quality

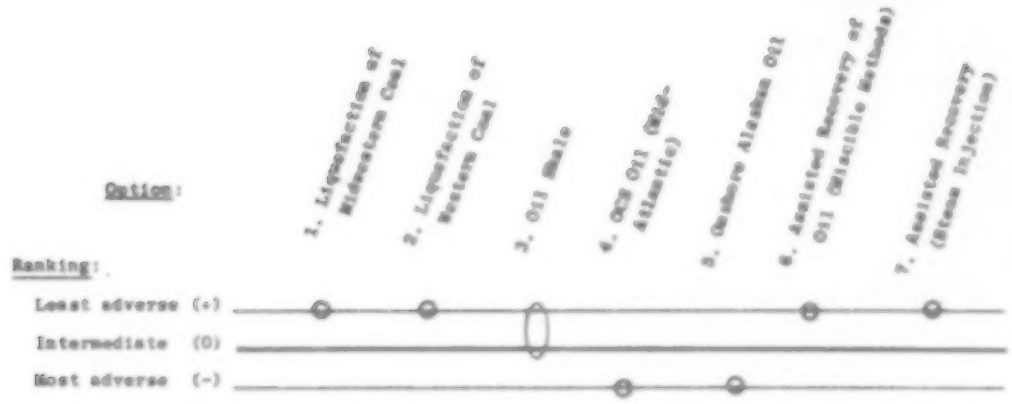
Direct impacts on water quality for coal liquefaction, oil shale, and assisted recovery operations can all be reduced to negligible amounts by either proper water treatment procedures or steps to ensure that

polluted water is not returned to streams or rivers. Indirect effects such as disruption or pollution of aquifers due to mining could have adverse effects for oil shale and coal liquefaction. An additional potential problem of oil shale is the possibility of failure of the catchment dam, the occurrence of which would result in the release of highly concentrated toxic salts into nearby streams. The limited analysis to date on these indirect effects has not established a case that they are likely to be severe;[29] future mining activities combined with careful monitoring will help resolve the issue.

The most serious environmental hazard of OCS oil development is the water quality impact of oil spills. Past experience has indicated that for medium and large offshore oil fields, the probability of a platform spill of between 1000 and 20,000 barrels during the lifetime of the field is 50 percent or greater.[28] Spills in this size range can be devastating to aquatic life if they occur near fertile estuarine areas or are brought into such areas by ocean currents before the oil has had time to decompose. Low levels of oil seepage can also affect aquatic life. The issues associated with the susceptibility of organisms to oil spills under varying circumstances and in different regions are complex and are the subject of Volume III of this report. Here it suffices to note that the adverse impact of oil spills relative to the water quality impacts of oil spills relative to the water quality impacts of the other options is large.

Water quality will also be adversely affected by onshore Alaskan development by oil spills from tankers, because we have assumed that the oil is piped to Valdez where it is shipped to the West Coast. The frequency of tanker collisions is less great than that of blowouts from OCS activities per unit of energy, but tanker collisions can cause very large spills of devastating impact.[30]

Rankings for Water Quality Impacts



D. Analysis of Critical Environmental Tradeoffs

1. Pro/Con Discussion

The following pro/con discussion summarizes the advantages and disadvantages of the options for increasing domestic oil supply.

Option 1: Liquefaction of Midwestern Coal in the Midwest

Advantages

- Small population impact; additional labor force can be largely supplied by present population.
- Abundant water relative to additional demand.
- Water quality impact is small if proper treatment and recycling are carried out.

Disadvantages

- Significant SO_2 and particulate impacts on air quality in densely populated area.

Option 2: Liquefaction of Western Coal in the West

Advantages

- Small water quality impact if proper treatment and recycling are carried out.

Disadvantages

- Potential for rapid population of sparsely populated areas, especially if the industry is geographically concentrated, e.g., the Powder River Basin.
- Large water requirements relative to availability could threaten instream flows or reduce availability for other uses, such as agriculture.
- Large emissions of NO_x --potential for photochemical oxidant formation.
- Potential for long-term land disruption due to strip mining land which is difficult or impossible to reclaim.

Option 3: Production of crude oil from oil shale

Advantages

- Small water quality impact if measures are taken to prevent leaching of spent shale piles into aquifers and streams and if depletion of upper Colorado is not excessive.

Disadvantages

- Large influx of workers and families into a sparsely populated, geographically concentrated region.
- High water consumption in water poor region.
- High levels of SO_2, NO_x, and particulate emissions.
- Significant land disruption due to disposal of spent shale in canyons.

Option 4: Oil from the Mid-Atlantic OCS

Advantages

- Negligible consumption of water.
- Insignificant levels of SO_2, NO_x, and particulate emissions.

Disadvantages

- Potential for serious land use impacts if onshore development occurs in undeveloped coastal regions.
- Serious water quality degradation due to chronic leakage and accidental spillage of oil.

Option 5: Oil from onshore Alaska

Advantages

- Negligible consumption of water
- Insignificant emissions of SO_2, NO_x, and particles.

Disadvantages

- Large social impacts due to influx of workers and their families into Alaska to build additional pipeline and port facilities.
- High probability of water quality degradation due to increased tanker traffic in heavily traveled zones--includes both high risk of collisions in addition to increased routine discharges.
- Land disruption problems due to additional drilling and construction in permafrost regions, laying of new pipelines in remote wilderness areas, and so forth.

Option 6: Assisted recovery of oil-miscible methods

Advantages

- Low level of social impacts.
- Existing water supplies are not strained.
- Negligible SO_2, NO_x, and particulate emissions.
- Additional land use is small due to development in existing fields.
- Low potential for water quality degradation.

Disadvantages

None

Option 7: Assisted recovery of oil-steam injection method

Advantages

- Low level of social impacts.
- Small potential for water quality degradation.
- Little additional land use.

Disadvantages

- High levels of SO_2 and particulate emissions if controls are not required.
- Potential for strain on water supplies in semi-arid regions.

2. Analysis of Critical Tradeoffs

Figure III-1 is a matrix summary of the advantages and disadvantages discussed in the previous section. The figure indicates a dominance of "most adverse" rankings for oil shale and of "least adverse" impacts for assisted recovery using miscible methods. Because of the degree of this dominance in the rankings for these two options, we are led to conclude that:

- Oil shale, using present technology is ranked the most environmentally degrading of the options to increase oil production
- Miscible methods of assisting recovery are ranked the least environmentally degrading of the options.

Establishing rankings for the intermediate five options for increasing oil production is a complex task. As we have discussed in Section D2 of Chapter II, the intermediate rankings depend on the relative importance one ascribes to the key adverse impacts and on the evaluation of the distribution of costs between beneficiaries and non-beneficiaries of the increased supply of oil. For the options evaluated in this chapter, placing a high value on an equitable distribution of social costs and benefits is equivalent to raising the rankings of coal liquefaction in the Midwest, OCS oil production in the Atlantic, and assisted recovery by steam injection (especially in California), since these options cause those who use the oil to suffer the adverse impacts of production. Similarly, valuing equity highly would lower the rankings of oil shale, onshore Alaskan oil, and coal liquefaction in the West, since these options cause adverse impacts on others than those who are the primary beneficiaries of the increased oil supply.

Table II-10 presents probable rankings for the seven oil supply options under five different "value judgment" assumptions. The options are grouped into one of four relative ranking categories: "most favorable," "favorable," "less favorable," and "least favorable," with no distinction

	Urbanization	Water Consumption Rel. to Availability	SO_2 Emissions	NO_x Emissions	Particulate Emissions	Aesthetics/Land Use	Water Quality
Midwest Coal Liquefaction	+	+	−	0	−	0	+
Western Coal Liquefaction	0	−	0	−	0	0	+
Oil Shale	−	−	−	−	−	−	+/0
OCS Oil (Atlantic)	0	+	+	+	+	0	−
Onshore Alaskan Oil	−	+	+	+	+	−	−
Assisted Recovery-Miscible Methods	+	+	+	+	+	+	+
Assisted Recovery-Steam Injection	+	0	−	−	−	+	+

+ = LEAST ADVERSE IMPACT

0 = INTERMEDIATE IMPACT

− = MOST ADVERSE IMPACT

FIGURE III-1. ENVIRONMENTAL TRADEOFF MATRIX FOR OPTIONS TO INCREASE DOMESTIC OIL SUPPLIES

Table III-10

PROBABLE RANKINGS OF THE OPTIONS TO INCREASE OIL SUPPLY UNDER DIFFERENT VALUE JUDGMENTS

KEY ASSUMPTION	I: All impacts of equal importance	II: Social equity of great importance	III: Social impacts of great importance	IV: Air pollution impacts of great importance	V: Oil spill impacts of great importance
RELATIVE RANKINGS:					
Most Favorable	Assisted Rec.-misc.	same as I	same as I	same as I	same as I
Favorable	OCS Oil-Atl.	same as I	same as I	same as I	Coal Liq.-W
	Coal Liq.-MW	same as I	same as I	---	same as I
	Alaskan Oil	Ass'd Rec.-steam	same as II	same as I	same as II
Less Favorable	Ass'd Rec.-steam	Alaskan Oil	same as II	same as I	same as II
	Coal Liq.-W	same as I	same as I	same as I	OCS Oil-Atl.
				Coal Liq.-MW	
Least Favorable	Oil Shale	same as I	same as I	same as I	same as I

made among options within one of the four categories. The five different sets of key assumptions are: (1) all impacts are of equal importance, (2) the value of social equity is high, (3) social impacts are of high importance, (4) air pollution impacts are of great importance, and (5) oil spill impacts are very important. In all cases, we have made reasonable assumptions about the meaning of the term "very important" in determining the ranking categories.

The important conclusion that we derive from studying the rankings in Table III-10 is that the rankings change very little for different assumptions about value judgments. The "base case" ranking, for which all impacts are assumed to have the same value, is presented in case I of Table III-10. If one chooses to stress social equity (case II), then assisted recovery by steam injection and Alaskan oil change places in the ranking categories. All other options remain unchanged in their rankings. Placing a high value on social impacts (case III) yields identical rankings as case II. Emphasizing the impact of air pollution (case IV) results in only one change in the "base case" ranking, coal liquefaction in the Midwest is moved from the "favorable" to the "less favorable" ranking category. Only for case V, in which a high importance is ascribed to oil spills, do the rankings change significantly. As we have indicated, our best judgment does not support assigning a high value to oil spill impacts.

We thus conclude that the rankings shown in cases I through IV of Table II-10 may be used to indicate the relative environmental impacts of the seven options to increase oil supply. Under a range of assumptions, oil shale receives the "most adverse" ranking and assisted recovery by miscible methods, the "least adverse" ranking. For the four different sets of assumptions in cases I through IV, OCS oil was ranked "favorable."

In three of the four cases, midwestern coal liquefaction was "favorable," and in one case, "less favorable." Alaskan oil and assisted recovery were "favorable" in two cases, and "less favorable" in two cases. Western coal liquefaction was "less favorable" in all four cases.

REFERENCES AND NOTES FOR CHAPTER III

1. "Project Independence Oil Task Force Report," Federal Energy Administration (November 1974).

2. "The Oil Producing Industry in Your State," the Independent Petroleum Association of America (1974).

3. Business Week, pp. 51-52 (November 1974). Some sources (e.g., Reference 3) suggest that this estimate may be somewhat high, unless oil prices increase substantially. Oil industry leaders have suggested that advanced recovery techniques could more than double U.S. onshore oil reserves, if the government increases financial incentives and price controls on oil, according to Energy Today (December 19, 1974).

4. The micellar flood method is sometimes termed a pseudo-miscible technique, because a microemulsion is formed rather than a solution to drive the oil. The terminology distinguishes micellar flood from CO_2 and hydrocarbon miscible techniques. One source, "Planning Criteria Relative to a National RDT and E Program Directed to the Enhanced Recovery of Crude Oil and Natural Gas," Gulf Universities Research Consortium (November 30, 1973), estimates that the percentage of oil expected from the different advanced recovery techniques are:

   Thermal, 29 percent
   Miscible, 71 percent
      a. Micellar, 58 percent
      b. Carbon dioxide, 8 percent
      c. Hydrocarbon, 5 percent.

   Other sources within the oil industry have confirmed that these are good approximate estimates. We have thus chosen to focus our attention on the micellar flood as a representative of the miscible techniques for enhanced recovery.

5. International Petroleum Encyclopedia, The Petroleum Publishing Company, pp. 299-305 (1974).

6. "Demonstrated Coal Reserve Base of the United States on January 1, 1974," U.S. Bureau of Mines (June 1974).

7. "Potential Future Role of Oil Shale: Prospects and Constraints," Federal Energy Administration, Project Independence Blueprint Final Task Force Report (November 1974).

8. "Geological Estimates of Undiscovered Oil and Gas Resources in the United States," U.S. Geological Survey Circular 725 (1975).

9. "Planning Criteria Relative to a National RDT&E Program Directed to the Enhanced Recovery of Crude Oil and Natural Gas," Gulf Universities Research Consortium (November 30, 1973).

10. "Oil: Possible Levels of Future Production," Federal Energy Administration Project Independence Blueprint Final Task Force Report (November 1974).

11. See Volume IV, Chapter VI, Section C for details.

12. "Air Quality for the Trans-Alaska Pipeline System: Stations and Remote Facilities," Alyeska Pipeline Service Company (April 1974).

13. "An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado, Colony Development Operation" (1974).

14. "Oil Shale Air Pollution Control," Stanford Research Institute (1975).

15. "Project Independence Report," Federal Energy Administration (November 1974).

16. The basis for the population estimates is presented in Chapter VIII. We have assumed an increase in the permanent work force of 14,000 per 10^{15} Btu output from coal liquefaction and a multiplier of 7 to account for workers' families and the increased population associated with new industries and services.

17. See Volume IV, Chapter III for a more complete discussion of social impacts of western energy development.

18. "OCS Oil and Gas--An Environmental Assessment," Council on Environmental Quality, p. 156 (April 1974).

19. The national average figures of 6250 oil and gas workers per 10^{15} Btu are derived from Reference 2. We have assumed a population multiplier of 7 to account for workers' families and persons employed in associated industries and services and their families. This multiplier is the same as that assumed for the sparsely populated western coal development areas, the basis for which is discussed in Chapter VIII. The estimates may be high for Alaska for two reasons: (1) the average oil well is expected to be substantially larger in Alaska than for the U.S. as a whole, requiring few workers per unit output, and (2) the family size of workers in Alaska may be smaller than for other parts of the U.S. For these reasons, we present our estimated population increase as a range, with the lower number corresponding to 50 percent of the high estimate. The lower estimate is in approximate agreement with that of the CEQ report, Reference 9, for Alaskan OCS activity.

20. "Synthetic Petroleum for Department of Defense Use," Stanford Research Institute (November 1974).

21. "Final Environmental Impact Statement of the Prototype Oil Shale Leasing Program," U.S. Department of Interior (1973).

22. The water consumption lower limit corresponds to roughly one barrel of water per barrel of oil recovered. Since some of the water which exits the assisted recovery operation with the oil may not be reinjected, we have assumed two barrels of water per barrel of oil as the upper limit.

23. Depending on the characteristics of the oil, between four and five barrels of water (to form steam) is required to produce one barrel of oil using steam injection. To recover one barrel of oil, one-third of a barrel is used to heat the water to produce the steam. Thus, between 6 and 7.5 barrels of water is required for the net production of one barrel of oil.

24. See Volume IV, Chapter IV for a discussion of the issues related to water availability in the West.

25. "Environmental Impacts, Efficiency, and Energy Supply and End Use," Hittman Associates, Inc., Vol. 1 (January 1975).

26. "Rehabilitation Potential of Western Coal Lands," National Academy of Sciences (1974).

27. Brown, T., "Oil on Ice--Alaskan Wilderness at the Crossroads," Sierra Club (1971).

28. "OCS Oil and Gas--An Environmental Assessment," Council on Environmental Quality, Executive Office of the President, Washington, D.C. (1974).

29. See Volume IV, Chapter V for details.

30. Kash, D. E., and I. L. White, "Energy Under the Oceans--A Technology Assessment of Outer Continental Shelf Oil and Gas Operations," University of Oklahoma Press (1973).

IV. EVALUATION OF ENVIRONMENTAL IMPACTS OF FOUR OPTIONS FOR INCREASING PIPELINE QUALITY GAS SUPPLIES

A. Introduction

Dwindling reserves of domestic natural gas combined with increasing demand for this resource have prompted increased activity to develop new sources of pipeline quality gas. Although LNG (liquefied natural gas) may be imported to help meet domestic demand, the recent emphasis on reducing U.S. dependence on foreign energy supplies indicates that new domestic sources of gas will be favored over imports. New areas, which have the potential of contributing significantly to U.S. gas supplies in the 1980s and beyond, are gas production from Alaska and the Outer Continental Shelf (OCS) regions and the gasification of coal.

This chapter presents, in summary form, information on the environmental and social impacts of four options for developing pipeline quality gas resources and compares these impacts in order to provide a basis for ranking the options. The four options considered are:

1. Mine western coal, gasify it on-site and pipe it to the Midwest.
2. Mine midwestern (Illinois) coal and gasify it near the site.
3. Produce gas from wells at off-shore locations (Atlantic and Southern California OCS) and pipe it ashore.
4. Produce gas from wells in Alaska, liquefy it, and ship it to the West Coast via LNG tankers.

As in the two preceding chapters, the indicators of impacts that have been selected to illustrate the types of problems associated with increasing supplies of pipeline quality gas are population, land use/aesthetic, water consumption relative to availability, SO_2, particulate, NO_x, and water quality impacts.

1. Technology and Impact Overview

To facilitate comparisons of impacts from the four options, two of which will have impacts markedly different from those of the other two, we present a brief overview of the technologies and the areas where critical impacts are likely to occur.

a. Gasification of western coal

Due to the large quantities and low extraction costs of coal deposits lying near the surface in the coal-bearing states of the western United States, this region is a primary candidate for resource development and conversion. In particular, the conversion of coal to pipeline quality gas or SNG (synthetic natural gas) is expected to be a large part of the energy conversion activities in the West. The first two commercial coal gasification plants in the preconstruction stages (El Paso and WESCO, see Volume IV, Chapter II) are based on Lurgi gasification technology and will utilize coal from the Navajo Reservation in the Four Corners area of New Mexico. Numerous other plants are planned for the Northern Great Plains area.

Advantages of using Lurgi technology are that it is presently commercially available and it is well adapted to using western coal.[1] Gasification is carried out at 1400°F and 400 psi in a fixed bed reactor in which coal is fed from the top by gravity, pressurized oxygen and steam are injected from the bottom, and ash is removed through a grate in the bottom. The resulting synthesis gas, containing mostly CO and H_2 and about 5 percent methane, is then quenched to remove tar and oils,

further reacted with steam to adjust the H_2/CO ratio to about 3, purified to remove hydrogen sulfide and other contaminants, and finally catalytically converted to 900-1000 Btu/SCF pipeline quality gas.

Future plants will probably utilize more advanced technologies, such as the Synthane and Hygas processes.[1] The Synthane process is similar to Lurgi except that a fluidized bed is used in which the reacting coal particles are kept in turbulent motion by the streams of oxygen and steam. This results in more efficient utilization of carbon in the coal and shorter residence times in the reactor. The Hygas process is conceptually different from either the Lurgi or Synthane processes in that hydrogen-rich gas rather than steam/oxygen is used as the gasifying medium. The hydrogen is obtained by gasifying char (a carbon-containing byproduct of gasification) in the presence of steam and oxygen. The reaction of hydrogen with coal in the reactor results in a high direct yield of methane from the Hygas reactor.

The major adverse impacts of gasifying coal in the western U.S. are likely to be as follows: (a) rapid urbanization of relatively undeveloped areas due to the large influx of workers and their families for mining, construction, and plant operation and maintenance; (b) water consumption where water availability is limited, threatening instream flows during drought years; and (c) disturbance through strip mining of large land areas whose reclamation may be difficult. Other potential problems such as air pollution may become significant, if large complexes of plants are sited in a small area or if siting is permitted in locations, of which there are many in the West, whose topography and wind conditions increase the persistence of the pollutants in the air (see Chapter VI, Section D).

b. Gasification of midwestern coal

The large deposits of high-sulfur coal in the Midwest can be converted to clean, low-sulfur gas. During SNG production, the raw synthesis gas is scrubbed to remove sulfur-containing compounds, which are subsequently converted to elemental sulfur. Any remaining sulfur compounds are removed by absorbers prior to methanation, since even small amounts of sulfur compounds poison the methanation catalysts. This conversion of midwestern coal to SNG may be one of the most important uses for it, given the uncertain market for high-sulfur fuels and the rising demand for clean fuels.

Due to the caking properties of midwestern coal, which cause plugging of the ash-removal grate in a fixed-bed gasifier, the Lurgi process is not suitable for this application. Although another commercially available technology--the Koppers-Totzek gasifier--could be used, its large oxygen consumption, atmospheric operation, and low direct methane yield tend to favor the further development and eventual use of more advanced technologies such as Synthane and Hygas, both of which are suitable for midwestern coal gasification.[1]

Large-scale coal gasification activities in the Midwest are not expected to result in extensive urbanization or water consumption problems. Major industrial centers such as Chicago and St. Louis can supply the necessary manpower, and water supplies are in abundance. Large-scale expansion of coal mining in rural counties could result in some urbanization impacts in these areas, however. An increase in ambient concentrations of SO_2 (and possibly sulfates) will undoubtedly result due to the significant quantities of SO_2 emitted from the gasification of high-sulfur coal. To the extent that gasification is carried out near urban centers, the already high ambient SO_2 levels could be raised above federal ambient air quality standards.

c. Production of natural gas in the Atlantic and Southern California OCS regions

The Outer Continental Shelf regions hold great promise for yielding new supplies of oil and natural gas. To effect rapid exploration and development of these regions, the Department of the Interior has recently proposed an accelerated leasing schedule involving 10 million acres per year in the Gulf of Mexico, Atlantic, California, and Gulf of Alaska regions. Due to the markedly different impacts of producing and shipping gas in Alaska, we treat this region in a separate section. Since the Gulf of Mexico has already undergone extensive development, we do not treat it as an area of new development, although greatly expanded production in this region could have significant impacts.

The impacts from the development of natural gas resources in new OCS regions will be mainly those associated with onshore development--pipelines, gas processing plants, and associated petrochemical industries. To the extent that natural gas production is associated with oil production, the impacts will be similar to those for OCS oil--especially those due to chronic and accidental oil spillage. The Natural Gas Task Force projects that about 50 percent of gas production in the Atlantic OCS will be from wells associated with oil deposits, and that 30 to 40 percent of gas production in the Pacific OCS will be associated with oil (both figures for 1985).[2] Therefore, for at least half of the gas production in new OCS regions, impacts are expected to result from the production of gas alone.

The onshore impacts of OCS gas production are strongly site specific, and are best examined on a site-by-site basis.* It is beyond

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*An example of such an analysis is provided in Volume 4 of the report "OCS Oil and Gas--An Environmental Assessment," prepared for the Council on Environmental Quality.[3]

the scope of this investigation to assess onshore impacts at specific sites. However, we do provide a general assessment of impacts that might be expected onshore in California and in the Atlantic coastal states.

d. Production of natural gas in Alaska and shipment via LNG tanker

The fourth alternative considered in this chapter for increasing domestic natural gas supplies is the development of gas reserves in the North Slope region and the Gulf of Alaska, piping the gas to port towns such as Valdez or Cordova, liquefying the gas, and transporting it to West Coast receiving areas via LNG tankers. Gas production is also expected to occur in other areas such as the Kenai Peninsula and Bering Sea OCS. However, we focus on the first two areas mentioned above since most of the production is expected to occur there.[2]

Gas from the North Slope may be transmitted either through a pipeline running parallel to the trans-Alaska oil pipeline to port facilities on the Gulf of Alaska for shipment via LNG tanker to the West Coast or across Alaska to Canada where it would interconnect with a pipeline system terminating in the Midwest. El Paso Natural Gas Company has applied to the Federal Power Commission for permission to construct the trans-Alaskan pipeline, while the Arctic Gas Company (a consortium of 27 American and Canadian firms) has applied for permission to build the trans-Canadian pipeline. It is not likely that both pipelines will be built; we have chosen to analyze impacts of the trans-Alaska pipeline.

Since most of the gas production in the Gulf of Alaska region is expected to be from nonassociated wells, oil spills will not result from this activity. Gas production from North Slope fields, on the other hand, is expected to be predominately from reserves associated with oil deposits.[2] Many of the impacts of OCS gas production in the Gulf of Alaska will be similar to those in the Atlantic and southern California regions, with the addition of impacts arising from the construction and operation of

liquefaction plants, the construction of port facilities and the higher levels of tanker traffic. Production of gas in the North Slope will involve the construction and operation of a new pipeline as well.

2. Energy Supply Potential of Options

The potential of each pipeline quality gas supply option for contributing to the nation's energy supplies is assessed by examining both the total quantity of resource available for extraction and a schedule for the production of gas. The availability of resources for the four options, as determined by recent estimates of recoverable reserves of coal and natural gas, is shown in Table IV-1. In Table IV-2, possible development schedules based on the Project Independence Blueprint "business as usual" and "accelerated development" scenarios are shown.

From the tables, it is clear that coal gasification has the greatest potential for contributing to the nation's long-term energy supply. Natural gas from OCS regions has a relatively low potential; however, further exploration and discovery could significantly change the reserve estimates. Due to the high level of oil development taking place in Alaska, and the resulting production of associated gas, this source of gas can make the greatest contribution in the near term, as shown in Table IV-2. Although significant production levels of OCS gas could be achieved by 1990, continued production at these levels would rapidly exhaust the reserves.

B. Conclusions

Based on the analysis and comparison of environmental impacts presented in Sections C and D of this chapter, we draw the following two conclusions regarding the relative merits of developing the pipeline quality gas options:

Table IV-1

RESOURCE AVAILABILITY FOR OPTIONS TO INCREASE PIPELINE QUALITY GAS SUPPLY

Option	Estimated Recoverable Reserves (trillion cubic feet)	Years of Supply at Present Consumption Level
1. Western coal[a] gasification	430	19
2. Midwestern coal[b] gasification	370	16
3. Atlantic and[c] Pacific OCS natural gas	14	0.6
4. Alaskan natural gas[c]	120	5.3

[a] Based on conversion of 50 percent of in-place surface reserves at 10,000 cubic feet per ton. Coal reserves from Reference 4.

[b] Based on conversion of 25 percent of in-place underground reserves and 50 percent of in-place surface reserves at 10,000 cubic feet per ton. Coal reserves from Reference 4.

[c] Most recent USGS estimates, Reference 5.

Table IV-2

POSSIBLE DEVELOPMENT SCHEDULES FOR PIPELINE QUALITY GAS PRODUCTION
(Trillion cubic feet per year)

Source		1980	1990
Coal gasification[a]	High	0.5	5.0
	Low	0.1	1.4
Atlantic and Pacific OCS[b]	High	0.2	1.8
	Low	0.1	0.8
Alaska[b]	High	0.9	3.4
	Low	0.8	1.8

[a] Derived from Reference 6.

[b] Derived from Reference 7.

1. The two most favorable options are the gasification of midwestern coal and the production of gas from the Atlantic and southern California OCS. For the gasification of midwestern coal, the only impact rated "most adverse" is the increased level of SO_2 emissions in the Midwest. The use of low-sulfur fuels within the gasification plants and judicious siting of the plants could significantly reduce both the level of emissions and the damage caused by them. For the production of gas from the OCS, the potentially significant problem of wetland disruption due to the laying of platform-to-shore pipelines could be mitigated through careful planning of pipeline routes.

2. Production of natural gas in Alaska and the gasification of western coal in the West are the two least favorable options for producing pipeline quality gas among the options considered. Gas production in Alaska is rated "most adverse" with regard to the high levels of nitrogen oxide emissions from gas liquefaction plants, the large influx of workers, their families, and associated population into small Alaskan towns, and the potential for disturbing virgin areas by pipeline construction. Gasification of western coal in the West has "most adverse" impacts associated with the urbanization of rural areas, high levels of water consumption in water-scarce areas, and the surface mining of land that may be difficult to reclaim. There is also a potential for significant degradation of air quality in parts of the West.

C. Analysis of Environmental and Social Impacts of the Options for Increasing Gas Production

The discussion of environmental impacts focuses on differences among the four options. Where these differences are very marked, the discussion focuses upon the judgments required to compare the alternatives. Where the differences are less marked, a more detailed technical discussion is required to present the differences and to clarify the basis for comparative value judgment.

1. Air Quality

Degradation of air quality is not a significant factor in gas production in the Atlantic and Southern California OCS, but it is a major

consideration in the two coal gasification options and Alaskan gas production. The emissions considered are sulfur dioxide, particulates, and oxides of nitrogen. Significant quantities of hydrocarbons (about 900 tons per 10^{12} Btu of gas produced--mostly in the form of methane)[3] are released by leakage during the production of OCS gas. However, these emissions occur far from shore and are readily dispersed. Thus, the impact on air quality is small.

a. SO_2 impacts on air quality

Estimates of SO_2 emissions for gasification of a typical low-sulfur western coal (18 million Btu/ton; 8.3 percent ash; 0.8 percent sulfur) vary from 30 to 76 tons of SO_2 per 10^{12} Btu output of gas depending on the process used.[8] The Lurgi process gives the values in the lower part of the range while the Synthane and Hygas processes produce emissions at a level corresponding to the upper part of the range.

Gasification of a typical high-sulfur midwestern coal (22 million Btu/ton; 11 percent ash; 3.5 percent sulfur) is estimated to emit 230 tons of SO_2 per 10^{12} Btu of gas produced by the Synthane process and 380 tons of SO_2 per 10^{12} Btu of gas produced by the Hygas processes.[8]

There are no federal standards for coal gasification plant emissions. However, the emission estimates can be compared with federal new source performance standards for coal-fired power plants, which allow no more than 600 tons of SO_2 per 10^{12} Btu input. On the basis of coal input into the gasification plants, SO_2 emissions are 3 to 5 percent of this level for western coal, and 21 to 33 percent of this level for midwestern coal.

Small SO_2 emissions will result from onshore processing of natural gas from OCS wells. Emissions resulting from the separation of natural gas liquids and removal of H_2S amount to only about 0.01 ton of SO_2 per 10^{12} Btu of gas processed.[8]

Impacts on air quality from the two coal gasification options are shown in Table IV-4, Section d. Based on this, we rank the impacts on air quality from SO_2 emissions as follows:

Rankings for SO_2 Impacts

	1	2	3	4
Option:	On-Site High Btu Gasification of Western Coal; Pipeline to Mid-west	On-Site High Btu Gasification of Midwestern Coal	Gas from Atlantic and Southern California Outer Continental Shelf	Gas from Alaska; Liquefaction; Transport by LNG Tanker to West Coast
Ranking:				
Least adverse (+)			O	O
Intermediate (0)	O			
Most adverse (-)		O		

b. Particulate impacts on air quality

Particulate emissions result from both the mining operation and the coal gasification processing. Particles emitted from mining operations and coal preparation are of relatively large diameter and are rapidly removed from the air by gravitational forces. They are also not nearly as injurious to health as fine particles, which are produced primarily from combustion processes. Thus, it is the combustion-derived particulates that are important for comparison of coal gasification alternatives. There are essentially no particulate emissions from the production of OCS gas. The onshore processing to remove natural gas liquids and H_2S results in the emission of about 0.3 ton of particulates per 10^{12} Btu of gas processed.[8]

Particulate emissions from coal gasification are estimated to be one to five tons per 10^{12} Btu for western coal using the Lurgi

process. The Synthane and Hygas processes emit approximately 25 and 12 tons of particulates per 10^{12} Btu respectively, using either western or midwestern coal.[8] (We have assumed the use of western coal typical of Montana and Wyoming. If coal from the Four Corners area is used, the particulate emissions for western coal are approximately doubled, because of the higher ash content of this coal.) The Lurgi process emits much less particulate matter because coal or process generated fuel gas is used to produce steam and power for the process while the considerable quantity of char (containing 30 to 60 percent ash) generated by the Synthane and Hygas processes is burned to provide power and steam. In those cases in which char or coal is combusted to provide steam and power, electrostatic precipitators or equivalent technology are assumed to remove 99.5 percent of the particulate matter in the stack gases. In practice, the removal efficiency for particulates less than 1 micron in diameter is much less.

The federal new source performance standard for particulate emissions for coal-fired power plants is 50 tons/10^{12} Btu input. The Synthane or Hygas process using western of midwestern coal results in particulate emissions of approximately 25 percent of related federal standards. However, the Lurgi process, using western coal, can limit emissions well below 5 percent of these federal standards. If higher ash western coal, typical of the Four Corners area of New Mexico, is utilized in the Synthane or Hygas processes, particulate emissions could approach 50 percent of the federal standard for coal-fired power plants.

As shown in Table IV-5, the air quality impacts of particulate emissions from western coal gasification can range from much less than to comparable with the impacts of midwestern coal gasification, depending on the process used. Thus, we rank the pipeline quality gas options as shown below.

Rankings for Particulate Impacts

Option:	1 On-Site High Btu Gasification of Western Coal; Pipeline to Mid-west	2 On-Site High Btu Gasification of Midwestern Coal	3 Gas from Atlantic and Southern California Outer Continental Shelf	4 Gas from Alaska; Liquefaction; Transport by LNG Tanker to West Coast
Ranking:				
Least adverse (+)				
Intermediate (0)				
Most adverse (-)				

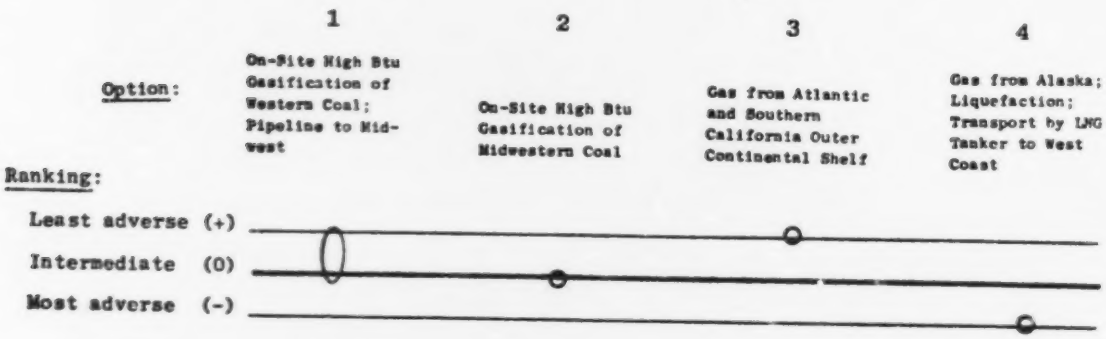
e. NO_x impacts on air quality

Estimates of NO_x emissions for the Lurgi gasification process are about 30-130 tons/10^{12} Btu. The Synthane process emits 180-200 tons/10^{12} Btu while the Hygas process has lower NO_x emissions, 110-120 tons/10^{12} Btu. The reason for the variation in NO_x emissions among the processes is the different fuels used to generate steam and power. There are no significant NO_x emissions for OCS gas production. Onshore processing and storage results in NO_x emissions of 14 tons/10^{12} Btu of gas processed.[8] In the case of Alaska, where the natural gas must be liquified before transporting via LNG tanker, about 13 percent of the gas must be consumed to operate the compressors and cooling apparatus in the LNG plant,[8] resulting in NO_x emissions of 300-1000 tons per 10^{12} Btu of gas processed, depending on the size of the engines used for compression and cooling.[9]

The new source performance standard for NO_x from coal-fired power plants is 350 tons/10^{12} Btu input. The Lurgi process with western coal emits 4 to 22 percent of the related federal standard. The Synthane and Hygas processes used with either type of coal will produce

emissions of 28 to 33 percent of the related federal standard. Liquefaction of natural gas can produce NO_x exceeding the performance standards for power plants. Air quality impacts are shown in Table IV-6. Although ambient NO_x concentrations resulting from natural gas liquefaction have not been calculated, they are expected to be somewhat higher than for the gasification options due to the higher emission levels.

Rankings for NO_x Impacts



d. Comparison of air quality impacts for the four options

The pollutant emissions of the piepline quality gas production options are summarized in Table IV-3. Air quality impacts are shown in Tables IV-4, IV-5, and IV-6.

Table IV-3

POLLUTANT EMISSIONS OF THE PIPELINE QUALITY
GAS PRODUCTION OPTIONS

	Emissions (tons/10^{12} Btu output)			
Pollutant/Process	Western Coal Gasification	Midwestern Coal Gasification	OCS Gas Production	Alaska
SO_2 (all processes)	30-80	230-380	<1	<1
Particulates			<1	<1
Lurgi	1-5*	--		
Synthane or Hygas	12-26*	11-22		
NO_x			14	300-1000
Lurgi	30-130	--		
Synthane or Hygas	120-200	110-180		

*These figures could be higher by a factor of 2 if high ash southwestern coal is used.

Table IV-4

SO_2 IMPACTS ON AIR QUALITY NEAR A 250 MILLION SCF/DAY PIPELINE QUALITY GAS PRODUCTION FACILITY

SO_2 Concentration/Ambient Air Quality Standard

Option	3 hr (Worst Case)			24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I	Class III	Class II	Class I
1. Western coal gasification	0.04-0.10	0.07-0.19	2.0-5.1	0.04-0.10	0.10-0.26	2.2-5.4	0.02-0.04	0.08-0.16	0.46-1.2
2. Midwestern coal gasification	0.23-0.38	0.43-0.71	12-20	0.20-0.33	0.52-0.86	10-17	0.07-0.11	0.28-0.44	2.1-3.4
3. OCS gas	Negligible								
4. Alaskan gas	Negligible								

Table IV-5

PARTICULATE IMPACTS ON AIR QUALITY NEAR A 250 MILLION SCF/DAY PIPELINE QUALITY GAS PRODUCTION FACILITY

Particulate Concentration/Ambient Air Quality Standard

Option	24 hr (Worst Case)			Annual Average		
	Class III	Class II	Class I	Class III	Class II	Class I
1. Western coal gasification	<0.001-0.03	<0.01-0.15	<0.02-0.50	0-0.006	<0.001-0.04	<0.002-0.07
2. Midwestern coal gasification	0.01-0.02	0.05-0.10	0.18-0.36	0.001-0.004	0.01-0.02	0.02-0.05
3. OCS gas	Negligible					
4. Alaskan gas	Negligible					

Table IV-6

NO_x IMPACTS ON AIR QUALITY NEAR A 250 MILLION SCF/DAY PIPELINE QUALITY GAS PRODUCTION FACILITY

NO_x Concentration/Ambient Air Quality Standard

Option	Annual Average
1. Western coal gasification	0.001-0.01
2. Midwestern gasification	0.004-0.01
3. OCS gas	Negligible
4. Alaskan gas	Significant, but not quantified

There are other considerations relevant to the determination of the air quality impact of these alternatives, however. These include dispersion characteristics of air pollutants due to the topography of the region, the health effects of given pollutant concentrations on the population at risk, and the aesthetic impact of additional air pollution. While these considerations have not been analyzed in depth in this study, some comments pertinent to differences between the coal gasification in the West and the Midwest can be made.

The effect of the pollutant concentrations on the health of the population is a function of both the population exposed to the pollutants and the absolute level of pollutants from other sources in addition to gasification. The high concentrations of population in the Midwest result in a given pollutant affecting considerably more people than in the West. The degree of aesthetic degradation resulting from adding air pollutants to presently clean air in the West or Alaska as

compared to adding an increment to the relatively polluted air of the Midwest is a value judgment that also deserves careful consideration.

In the case of gas production in Alaska, the large quantities of NO_x emitted during gas liquefaction could result in significant air quality degradation. This is especially true in port towns such as Valdez where there will be large quantities of hydrocarbon emissions. These will result from evaporation during storage and tanker loading operations related to OCS oil production and the trans-Alaska pipeline. The presence of high ambient levels of NO_x and hydrocarbons have the potential of forming significant levels of photochemical oxidants during the summer months.

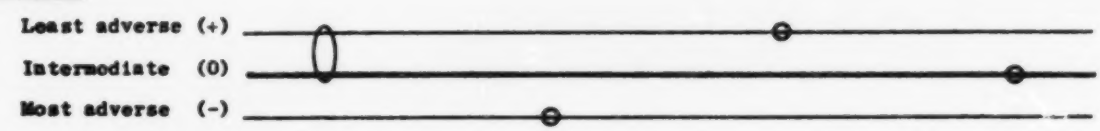
Based on the above considerations we judge that the impact on air quality from gas production in the Atlantic and southern California OCS will be the least of the three options, while coal gasification in the Midwest has the greatest potential impact. Even though all ambient air concentrations due to coal gasification are less than any federal standard, except the stringent Class I standard for SO_2, we judge that gasification of midwestern coal will have a relatively large air quality impact, due mainly to the significant concentrations of SO_2 attained and the potential for affecting large populations. Gasification of coal in the West will have a small impact on air quality if the Lurgi gasifier is used in conjunction with combustion of low-Btu gas, and a moderate impact if Synthane or Hygas gasifiers are used. Air quality in Alaskan ports could be significantly degraded depending on the degree to which NO_x and hydrocarbons interact in the Alaskan environment.

The above judgments are summarized in the following table which ranks overall air quality impacts for the four options.

Rankings for Overall Air Pollution Impacts

Option:	1	2	3	4
	On-Site High Btu Gasification of Western Coal; Pipeline to Mid-west	On-Site High Btu Gasification of Midwestern Coal	Gas from Atlantic and Southern California Outer Continental Shelf	Gas from Alaska; Liquefaction; Transport by LNG Tanker to West Coast

Ranking:



2. Population

Development of new industry in an area brings an increase in population not only from the workers directly involved but also from people drawn to the area to provide the industry and its employees support services. In addition, an influx of related industry can further swell the population. All four of the energy development alternatives for pipeline quality gas have the potential to bring about rapid population growth in limited regions. The differences lie in the rate of growth required, its distribution, and the size and capability of the established population to absorb the increase. The most serious problems are likely to occur in the Northern Great Plains region, the Southwest, and Alaska because there are few large urban complexes in these areas to support the short-term needs for goods and services of the new population.

For the coal gasification options, the magnitude of the problem can be estimated by noting Table IV-7 which shows the population increase resulting from construction and operation of one 250 million SCF per day (8.5×10^{13} Btu/year) gasification plant located in an isolated area. If it were located in a more densely populated region, such as the

Midwest, much of the associated services and industry would be already located nearly.

Table IV-7

POPULATION INCREASE DUE TO CONSTRUCTION AND OPERATION OF A 250 MILLION SCF PER DAY COAL GASIFICATION PLANT

	Permanent	Temporary (Peak)
Plant workers	880[a]	3500[a]
Mining workers	370[a]	
Families of workers	3400[b]	7100[b]
Workers in associated industry and families	1350[b]	9900[b]
Total increase	6000	20,000

[a] Reference 10.

[b] Reference 11.

A typical energy growth scenario, such as that described by the Project Independence Report, forecasts 33 to 59 gasification plants by 1990 for "accelerated" and "unrestricted" energy development scenarios, respectively.[6] Many of these gasification plants are likely to be in the Northern Great Plains region. Thirty-five plants built in the region, corresponding to three quadrillion Btu output per year by 1990, could cause an influx of 350,000 people (210,000 permanent) during the next 15 years, giving an average growth rate in the permanent population above the present 450,000 population of 2.5 percent per year for the Northern Great Plains coal region as a whole, in addition to the influx of temporary workers. While this growth rate is not extreme were it distributed evenly, it is likely that there will be locations (especially near large coal fields) of rapid growth of 10 percent per year or more. The adverse impacts

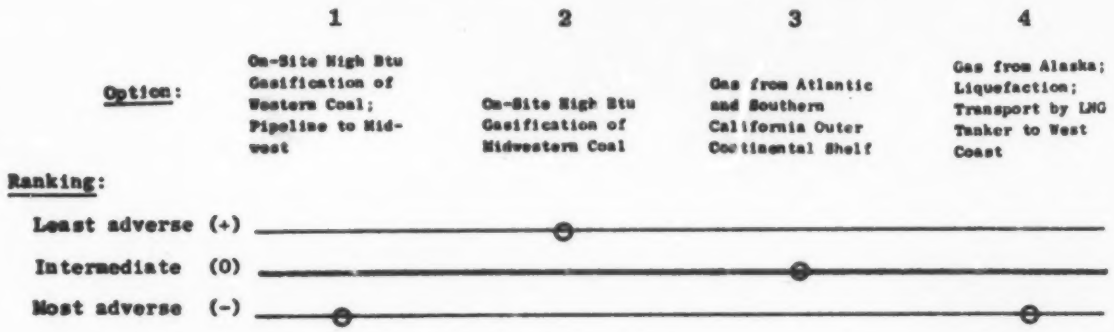
of such rapid growth are likely to be serious, as described in Volume IV, Chapter III.

The onshore urbanization impacts of OCS gas production in California and the Atlantic Coast regions depend largely on whether or not the gas is associated with oil. The reason for this is that oil refineries and related upgrading facilities are likely to cause substantially larger population impacts than gas processing facilities. Offshore production of one quadrillion Btu per year on the Atlantic or Southern California Coast (about 20 percent of which is gas) is expected to stimulate a population increase of 125,000. Probably no more than five to ten percent of this figure is due to gas production and processing. We thus conclude that in recreational/rural regions of the Atlantic Coast or Southern California, the urbanization impact of new OCS gas production is likely to be moderate, although that due to oil and gas production combined could be somewhat more severe.[3]

In Alaska, the projected population increase due to one quadrillion Btu per year of OCS production (about 40 percent of which is gas) is about 16,000.[3] This increase is associated with production, tanker loading, and gas processing and liquefaction. The population influx due to OCS gas production, in addition to that induced by a new trans-Alaska pipeline, is likely to create boomtown conditions in the small Alaska coastal towns, which are destined to become major ports and processing centers, as well as in towns such as Fairbanks, which lie along the pipeline route.

The relative urbanization impacts of the four options for pipeline quality gas production are shown below, reflecting the severity of impacts in Alaska and the West, and the potential impacts on coastal regions if rural and recreational areas are developed.

Rankings for Population Impacts



3. Land Use and Aesthetic Impacts

Land use impacts for the four gas supply alternatives consist of the denial of land areas for other potential uses and changes in the aesthetic and biological environment of the land through the addition of surface mines, plants, solid waste piles, pipelines, drilling rigs, etc. The four alternatives have significant differences in their land use impacts.

The most severe land use impact from gasification of western or midwestern coal results from strip mining of the coal. A typical western strip mining operation will disturb 400 to 500 acres per year to supply a 250 million SCF per day gasification plant.[12] This means that approximately 9000 acres of land will be disturbed over the 20-year life of the plant. Since at least five years is required to achieve reclamation of strip mined land in the West,[12] over 2200 acres will be unreclaimed at any given time. In arid regions and regions with poor topsoil, reclamation may take much longer than five years, or may not be achieved at all.[10] Therefore, this figure should be regarded as a minimum estimate.

In the Midwest, coal seams are thinner and more acres must be stripped per ton of coal recovered.[13] Even with the lower tonnage of coal required for a gasification plant using midwestern coal, nearly 19,000

acres of land will be disturbed over 20 years. Reclamation occurs at a faster pace (three years on the average) in the Midwest due to higher rainfall and more fertile soil, so that at any given time about 2800 acres will be unreclaimed. If coal is produced by underground mining in the Midwest, subsidence could affect 1300 acres per year.[13] Even though the effects of subsidence are permanent, they do not necessarily remove the land from other uses, such as grazing.

The other major difference in land use impacts between options 1 and 2 is the pipeline right-of-way. Rights-of-way for pipelines are typically 50 to 75 feet,[13] and a pipeline from the West to the Midwest (Illinois) would be about 1000 miles long. Thus, including pumping stations, about 8000 acres would be affected. Extending these figures to a 35 plant industry in the Northern Great Plains region (assuming a single pipeline has a capacity of one billion SCF/day), as many as 70,000 acres could be devoted to pipeline rights-of-way. Although the pipelines will have little aesthetic impact once the pipe is buried, the construction phase will cause considerable temporary land disturbance. On a long-term basis, the land occupied by the pipeline right-of-way is effectively removed from other uses. Midwestern coal mines and gasification plants are near to the users of gas and thus would require much shorter pipelines than western development locations.

Both western and midwestern gasification plants will occupy a land area of about 1000 acres.[3] Ash disposal (3000 to 4000 tons/day) is assumed to take place in mined-out areas, thus requiring no additional land area.

The most serious land use impact of OCS gas production in the Atlantic and Southern California coastal areas is that due to the construction of pipelines connecting the offshore production platforms with onshore processing plants. Where drilling and production

associated with OCS gas development are visible from shoreline recreation areas, there will be considerable aesthetic impact. If pipelines traverse wetlands and estuarine regions, the dredging and spoil activities can have a significant adverse impact on the biological diversity and productivity of the region. Effects can occur due to habitat disruption, increased turbidity, and fluctuating salinity levels.[14] This impact is extremely site dependent, and to the extent that pipelines can be diverted from wetlands and estuaries, the most severe impacts can be avoided.

The onshore land use of gas processing plants is not large, amounting to about 12 acres for a 250 million SCF per day processing plant,[13] and about 20 acres for a similar size liquefaction plant[13] for transport of Alaskan gas.

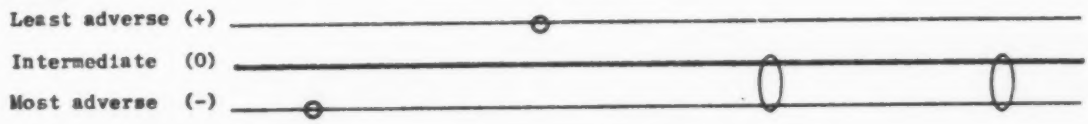
For gas production from the North Slope, the addition of a new gas pipeline paralleling the existing trans-Alaska oil pipeline will create significant temporary land disturbance. The long-term effect will be little different from that created by the oil pipeline since most of the land disturbance will have already taken place (road building, disruption of tundra, etc.).[15] A decision to route the gas pipeline to Cordova instead of Valdez could disturb significant new areas of virgin lands, however.

Due to the potential for long-term land disruption in the West, we rank option 1 as having the most adverse land use impact, while option 2 is ranked least adverse due to the ease of reclamation in the Midwest. The intermediate-to-most adverse ranking of options 3 and 4 reflects the uncertainty as to the extent to which new land will be disturbed by the gas pipeline and the site specific impact of platform-to-shore pipeline construction.

Rankings for Aesthetic/Land Use Impacts

	1	2	3	4
Option:	On-Site High Btu Gasification of Western Coal; Pipeline to Mid-west	On-Site High Btu Gasification of Midwestern Coal	Gas from Atlantic and Southern California Outer Continental Shelf	Gas from Alaska; Liquefaction; Transport by LNG Tanker to West Coast

Ranking:



4. Water Consumption

Water consumption is a potentially significant impact for activities requiring large amounts of water in regions of limited availability. For three of the four options, these conditions are not present. Water supplies in the Midwest are relatively abundant and offshore drilling, gas production, and gas processing requires insignificant amounts of water.

Western coal gasification presents a different story. The water requirements for a 250 million SCF per day plant and associated mine are shown in the following table:

Table IV-8

WATER CONSUMPTION OF 250 MILLION SCF PER DAY COAL GASIFICATION PLANTS

Coal Gasification Process	Water Requirements--(thousand acre-feet/year)[11]
Lurgi	10-17
Synthane	18-26

A vigorous energy development scenario in the Northern Great Plains region typically involves at least 30 such plants by 1990 resulting in potential water requirements up to 750,000 acre-feet per year, in addition to water requirements for power plants and other energy-related activities.

The consumption requirements can be compared with the potential future water availability in the Missouri Basin, which is the primary western coal development region. The amount of future water considered available is a sensitive function of the restrictions that are placed on water resources. As an upper limit, 10 million acre-feet per year above present use could be used by energy industry and still maintain minimum flow throughout the worst drought period previously experienced.[16] However, new allocation and usage above 2 million acre-feet per year could begin to lower instream flows such as to threaten aquatic life during periods of drought throughout the basin.[16] Allocation of water to energy uses will compete directly with the anticipated growth of agricultural and urban requirements, projected to reach the instream flow threshold of 2 million additional acre-feet per year before the year 2000. Finally, such heavy use of water at selected locations in the basin would require additional dams and aqueducts to provide the necessary storage and distribution network.

We thus conclude that an extensive western coal gasification industry is likely to require sacrifice of the aquatic life of the streams of the Missouri Basin, or future agricultural and urban uses of water, or both, as well as to require a network of dams and aqueducts throughout the basin.

Thus, we judge that the gasification of western coal will have the most adverse impact on water supply in a potentially water deficient region. Midwestern coal gasification and OCS gas production will have small or negligible impacts. These judgments are reflected in the table below.

Rankings for Water Consumption Relative to Availability Impacts

Option:	1 On-Site High Btu Gasification of Western Coal; Pipeline to Mid-west	2 On-Site High Btu Gasification of Midwestern Coal	3 Gas from Atlantic and Southern California Outer Continental Shelf	4 Gas from Alaska; Liquefaction; Transport by LNG Tanker to West Coast
Ranking:				
Least adverse (+)		○	○	○
Intermediate (0)	———	———	———	———
Most adverse (-)	○			

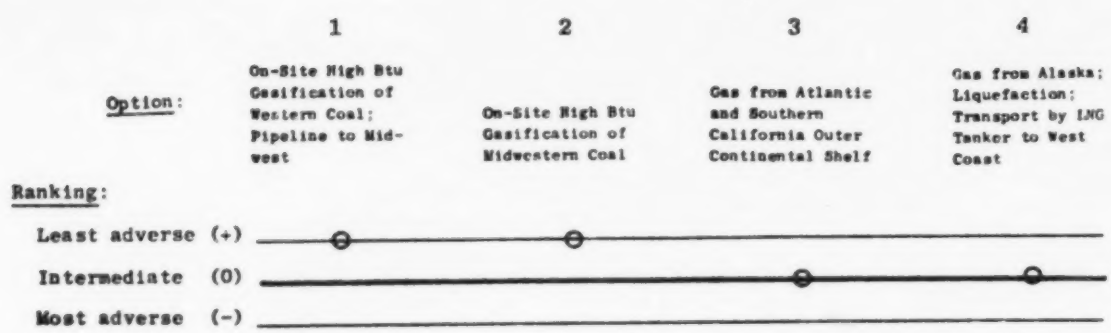
5. Water Quality

The water quality impact of coal mining and gasification processes can be relatively well controlled using established technology. Thus, nearly all the recent applications for coal gasification plant developments have proposed complete disposition of all excess water on-site with no return discharge to the reservoir or river. Means of achieving this include the use of evaporation ponds, injection into deep underground aquifers, and treatment for recycling into the gasification process.[14] The remaining sources of potential water pollution are the contamination of underground aquifers by either mining operations or deep injection of the highly saline process water, leaching of salts from the ash disposal piles and deposition into local streams, and increases in the salinity of downstream flows from depletion of upstream water.[14] Not enough is known of these effects to allow credible quantitative estimates of their impact. The few attempts at quantitative assessment located during the course of this study have suggested that none of these effects is likely to be of significant impact. Nonetheless, potential water quality problems could be significant; the need for monitoring of water quality near coal mining and processing sites is a real one.

To the extent that gas in offshore regions is found in conjunction with oil, water quality impacts are mainly those due to the oil spills associated with the parallel activities of drilling and piping the oil and gas to shore. The effect on water quality and marine life of both chronic and massive accidental oil spills is discussed in Chapter V. Where nonassociated gas is produced, the main water quality impacts will be the dumping of drill cuttings and drilling mud into the ocean.[11] However, these impacts are expected to be minimal since washed drill cuttings are relatively inert in the marine environment and drilling mud has commercial value and can either be reused on-site or sold. Discharges of other contaminants, such as sewage and waste water, are also expected to be small. The water quality impacts of onshore gas processing or liquefaction facilities will also be minimal.[4] However, in Alaska, the increase in offshore traffic due to LNG tankers increases the likelihood of oil tanker collisions resulting in oil spillage.

As shown below, we judge OCS and Alaskan gas production to have a moderate impact compared to coal gasification due to the potential for oil spillage in areas where gas is produced concurrently with oil.

Rankings for Water Quality Impacts



D. Analysis of Critical Environmental Tradeoffs

1. Advantages and Disadvantages of Each Option

To clarify and summarize the discussion in Section C, we present below a brief statement of the advantages and disadvantages of each option for increasing pipeline quality gas production.

Option 1: Mine western coal, gasify it on-site, and pipe it to the Midwest

Advantages

- Potential for degrading water quality is small.
- Low level of SO_2 emissions compared to equivalent federal performance standard.
- Low level of particulate emissions if Lurgi technology is used in conjunction with low-Btu gas combustion.

Disadvantages

- Large urbanization impact in sparsely populated areas.
- Large consumption of water in water scarce regions.
- Potential for long-term land disturbance.
- Potential for significant particulate emissions if Synthane or Hygas technologies are used with southwestern coal.

Option 2: Mine midwestern coal and gasify near the site

Advantages

- Low potential for large-scale urbanization impact.
- Does not strain available water supplies.
- Low potential for degrading water quality.
- Small land use impacts.

Disadvantages

- Significant levels of SO_2.

Option 3: Drill and produce gas at offshore locations (Atlantic and Southern California OCS) and pipe it ashore

Advantages

- Negligible SO_2, particulates, and NO_x.
- Negligible water consumption.
- Small water quality impact for production of nonassociated gas.

Disadvantages

- Potential for biological disruptions in estuaries and wetlands due to pipeline construction.

Option 4: Drill and produce gas in Alaska, liquefy it, and transport it to the West coast via LNG tanker

Advantages

- Negligible SO_2 and particulates.
- Negligible water consumption.

Disadvantages

- Large urbanization impact in coastal towns and along pipeline route.
- Potential for significant land disturbance due to new pipeline construction.
- Large amount of NO_x.

2. Analysis of Critical Tradeoffs

In Figure IV-1 the environmental rankings for the four options are summarized.

	SO_2 Impacts	NO_x Impacts	Particulate Impacts	Population Impacts	Aesthetics/Land Use	Water Consumption Rel. to Availability	Water Quality
GASIFICATION IN WEST	0	$\frac{+}{0}$	$\underline{0}$	−	−	−	+
GASIFICATION IN MIDWEST	−	0	0	+	+	+	+
OCS GAS (ATLANTIC & CALIFORNIA)	+	+	+	0	$\underline{0}$	+	0
OCS GAS (ALASKA)	+	−	+	−	$\underline{0}$	+	0

+ = LEAST ADVERSE IMPACT 0 = INTERMEDIATE IMPACT. − = MOST ADVERSE IMPACT

FIGURE IV-1. ENVIRONMENTAL TRADEOFF MATRIX FOR OPTIONS TO INCREASE PIPELINE QUALITY GAS PRODUCTION

Based on the rankings in this figure, we conclude that:

1. The two most favorable options are the gasification of midwestern coal and the production of gas from the Atlantic and southern California OCS. For the gasification of midwestern coal, the only impact rated "most adverse" is the increased level of SO_2 emissions in the Midwest. The use of low-sulfur fuels within the gasification plants and judicious siting of the plants could significantly reduce both the level of emissions and the damage caused by them. For the production of gas from the OCS, the potentially significant problem of wetland disruption due to the laying of platform-to-shore pipelines could be mitigated through careful planning of pipeline routes.

2. **Production of natural gas in Alaska and the gasification of western coal in the West are the two least favorable options for producing pipeline quality gas among the options considered. Gas production in Alaska is rated "most adverse" with regard to the high levels of nitrogen oxide emissions from gas liquefaction plants, the large influx of workers, their families and associated population into small Alaskan towns, and the potential for disturbing virgin areas by pipeline construction. Gasification of western coal in the West has "most adverse" impacts associated with the urbanization of rural areas, high levels of water consumption in water-scarce areas, and the surface mining of land that may be difficult to reclaim. There is also a potential for significant degradation of air quality in parts of the West.**

In the case of pipeline quality gas production, we conclude that the tradeoff issues are clearly defined and that the data we have presented provide a relatively sound basis for ranking. The rankings are generally independent of the value ascribed to the different impact categories and to the importance placed on issues of social equity, as thoughtful consideration of Figure IV-1 will indicate. We thus formulate the following two recommendations:

- Further research and development on technologies, such as the Synthane and Hygas processes, which can convert high-sulfur midwestern coal to low-sulfur gaseous fuel while minimizing SO_2 should be strongly emphasized.
- Before any large-scale development of western coal gasification or natural gas reserves in Alaska is carried out, substantial analysis and preplanning is required to reduce the impacts of urbanization and to fully assess and minimize the magnitude of environmental disruption.

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16. See discussion of water requirements and water supplies in Volume IV, Chapter IV.

17. See discussion of water pollution potential of synthetic fuel plants in Volume IV, Chapter V.